ALBERTA

ENERGY RESOURCES CONSERVATION BOARD

DECISIONS

1989-90

DECISIONS

ISSUED IN 1989

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D 89-2	880953	Transalta Utilities Corporation 240-KV Transmission Line ELLERSLIE-EAST EDMONTON AREA	10 May 1989
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MEMORANDUM	880953	TRANSALTA UTILITIES CORP. THE CITY OF EDMONTON (EDMONTON POWER) 240-kV TRANSMISSION LINE ELLERSLIE-EAST EDMONTON AREA	15 September 1989
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D 89-10	891207	GANNON BROS. ENERGY LTD. APPLICATION FOR A WELL LICENCE EWING LAKE FIELD	26 October 1989
Memorandum	891549	CANADIAN WESTERN NATURAL GAS CO. APPLICATION FOR A PIPELINE PERMIT MAGRATH AREA	24 November 1989
D 89-11	891549	APPLICATION BY CANADIAN WESTERN NATURAL GAS COMPANY LIMITED FOR A PERMIT TO CONSTRUCT A PIPELINE TO TRANSPORT NATURAL GAS IN THE MAGRATH AREA	27 December 1989
MEMORANDUM	890007	THE CITY OF EDMONTON (EDMONTON POWER) JOINT OWNERSHIP 500-kV TRANSMISSION SYSTEM KEEPHILLS-ELLERSLIE	1 May 1989

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

RUSTUM PETROLEUMS LIMITED
SPECIAL GAS WELL SPACING
CYGNET AREA

Decision D 89-1
Application 880526

1 INTRODUCTION

1.1 The Application

Rustum Petroleums Limited applied under section 4.050 of the Oil and Gas Conservation Regulations (the Regulations) for an order establishing fractional section 20 of township 39, range 28, west of the 4th meridian (fractional section 20), as a special drilling spacing unit (DSU) for the production of gas from the Glauconitic Sand. The target area would be legal subdivision (Lsd) 8 of the fractional section.

1.2 The Interventions

GNE Resources Ltd., a lessee of mineral rights in section 13 of township 39, range 1, west of the 5th meridian (section 13), submitted an intervention to the application. An intervention was also submitted by Richard C. Siegfried on behalf of Arlene Feagan, Harry Hueppelsheuser, and Juanita Siegfried, who are mineral rights owners in the northeast quarter and the north half of the southeast quarter of section 21 of township 39, range 28, west of the 4th meridian (section 21). Philip and Agnes Schmidt, who are mineral rights owners in fractional section 17 of township 39, range 28, west of the 4th meridian, submitted a letter indicating their interest in fractional section 17, but did not participate in the hearing.

1.3 The Hearing

The application was considered at a public hearing on 14 and 15 December 1988, in Calgary, Alberta, by a division of the Board comprised of N. A. Strom, P.Eng. (Chairman), E. J. Morin, P.Eng., and Acting Board Member H. Antonio, P.Eng.

Those who appeared at the hearing and abbreviations used in this report are listed in the following table.

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Rustum Petroleums Limited (Rustum) R. A. Neufeld	B. P. Morrison J. B. Hughes, P.Geol. G. D. Metcalfe, P.Eng. of Fekete Associates Inc.
GNE Resources Ltd. (GNE) S. Carscallen	C. W. Chapman, P.Eng. of Chapman Petroleum Engineering Ltd. R. C. Mann, P.Geol. of Hume, Mann & Associates Ltd.
Richard C. Siegfried (the Lessors) T. M. Hughes	R. C. Siegfried, P.Eng. J. M. Gunn, P.Eng. B. L. Hamilton, P.Geol. all of ICG Resources Ltd.
Energy Resources Conservation Board staff C. C. South M. Connelly K. Fisher C.J.C. Page	

2 BACKGROUND

The 5th meridian defines the west boundary of fractional section 20, resulting in the fractional section being about 151.9 hectares (ha) rather than the normal 256 ha. In 1985, Rustum drilled the well, RUSTUM GILBY A8-20-39-28 (W4M) (the A8-20 well) in fractional section 20 as a prospective oil well in accordance with normal oil DSUs of one-quarter section. However, the well encountered gas in the Glauconitic Sand and, in accordance with section 4.050 of the Regulations, gas production operations cannot commence at the A8-20 well until fractional section 20 has been established as a special gas DSU with a unique target area.

Rustum is the lessee of mineral rights in both fractional section 20 and section 21. The mineral rights in fractional section 20 are owned by the Crown and in section 21 by a number of freehold owners.

3 CONSIDERATION OF THE APPLICATION

3.1 Views of Rustum

Rustum submitted that the application, if approved, would allow penalty-free gas production from fractional section 20. Rustum indicated that the A8-20 well was drilled on an existing well-site lease at the edge of the Blindman River Valley, with the location of the existing well site having been agreed to by the surface owner. The A8-20 well was drilled on target for oil production, being approximately 445 metres (m) north and 234 m west of the southern and eastern boundaries of fractional section 20. No target area for drilling and producing a gas well on fractional section 20 was considered prior to drilling, since gas was not expected. In the end, the A8-20 well did not encounter oil but instead encountered gas in the Glauconitic Sand.

Rustum interpreted the Glauconitic sands in the area as being deposited in a complex depositional environment. Rustum identified three sand facies, channel sands, bar sands, and overbank sands, which it considered to be frequently discontinuous and characterized by low permeability. Rustum's interpretation was that the A8-20 well encountered a lense of bar (Glauconitic B) and overbank (Glauconitic A) sands that is separated from other lenses in offsetting sections. Rustum's interpretation of the Glauconitic A and B sand pools in and around the area of application is shown in Figures 1 and 2.

With respect to pressure data, in considering that the reservoir pressure at the A8-20 well is in the same range as that of offsetting Glauconitic gas wells, Rustum acknowledged that where insufficient production history is available, pressure data is inconclusive in determining the size and continuity of the reservoir sands. However, Rustum concluded that deep pressure sinks at the offsetting Glauconitic oil wells in Lsd 14-16-39-28 W4M (the 14-16 well) and in Lsd 6 of section 21 (the 6-21 well) and the absence of significant pressure decline at other nearby Glauconitic gas wells, specifically a well in Lsd 14 of section 21 (the 14-21 well), demonstrate that the Glauconitic zone at each of the oil wells is a small, separate, hydrocarbon accumulation. Rustum used these pressure phenomena to support its geological interpretations and geological inference that the A8-20 well had penetrated a small hydrocarbon accumulation, separated from offsetting Glauconitic wells including those in sections 21 and 13.

Rustum submitted that there are no valid reasons for prohibiting or restricting production from the A8-20 well. It indicated that not only is increased gas deliverability desirable from a conservation point of view, but it would also allow Rustum to meet its gas sales obligations

in the area. Rustum pointed out that it had a deliverability-type sales contract that presently would provide for combined sales from fractional section 20 and section 21 of some 56 thousand cubic metres per day (10^3 m^3/d) or 20 million cubic metres per year (365 days) (10^6 m^3/yr). The minimum annual quantity that the purchaser must buy is 45 per cent of that, or 9 x 10^6 m^3/yr. Rustum acknowledged that a rate of about 1 x 10^3 m^3/d from the A8-20 well would suffice to cover daily operating costs but would not provide for recovery of capital.

Rustum argued that even if the sands were continuous, as suggested by the interveners, the effect of production from the A8-20 well on the recovery of reserves from the 14-21 well and wells in Lsds 14 and 16 of section 13 (the 14-13 and 16-13 wells, respectively) would be minimal. Concerning section 13, Rustum noted that fractional section 20 has more reserves, based on GNE's interpretation of reserves, and has less deliverability than section 13. Concerning section 21, Rustum noted that based on its estimate of productivity decline and using the Lessors' interpretation of reserves, it would take some 20 years for two wells to deplete the reserves underlying fractional section 20 and section 21.

Rustum indicated that it had considered as a method of obtaining its share of production from fractional section 20, the possibility of creating an enlarged special DSU consisting of fractional section 20 and section 21. It submitted, however, that the establishment of an enlarged DSU and the pooling of mineral ownership within that DSU would be fraught with difficulties and would not be in the best interest of mineral owners.

Rustum considered that the most reasonable method of obtaining its share of production from fractional section 20 would be to establish fractional section 20 as a special DSU. Rustum believed that its application satisfied the criteria for a reduction in spacing, as set out in section 4.030(3) of the Regulations, on the following basis: additional wells are needed to drain the pool at a reasonable rate, increased deliverability in the area is desirable, and producing the A8-20 well would improve recovery.

Assuming that fractional section 20 is designated as a special DSU, Rustum proposed that the A8-20 well be deemed to be completed within its target area. Rustum submitted that one of the objectives of having a central gas target in a one-section spacing unit is to maintain a degree of equity with offsetting interests. Equity, however, would not be an issue since, by Rustum's interpretation, the A8-20 well penetrated an isolated gas pool and therefore would not drain gas reserves in offsetting lands. Even if the A8-20 well were in communication with offsetting wells, Rustum pointed out that the interwell distances

between the A8-20 well and neighbouring Glauconitic gas wells exceed the minimum interwell distance of 600 m associated with adjoining normal one-section gas DSUs with central targets.

Considering factors including these: that the surface terrain and land use in Lsd 8 of fractional section 20 had restricted where a well could be located, that the area in question is a fractional section, and that the A8-20 well meets the minimum interwell distance requirement of 600 m from offsetting wells, Rustum submitted that the normal 300 m setback from the sides of a DSU for gas target spacing would not be appropriate in this case.

3.2 Views of GNE

GNE, a lessee of mineral rights in section 13 which offsets fractional section 20 to the southwest, agreed that Rustum should have the opportunity to produce the gas reserves underlying fractional section 20. However, it believed that Rustum's proposal of penalty-free production of Glauconitic gas reserves from the A8-20 well could lead to unfair drainage of Glauconitic gas reserves in section 13.

GNE's geological interpretation of the Glauconitic zone was similar to that of the applicant in that it considered the sand facies to be a result of complex depositional systems. GNE traced two upper sands, the Glauconitic A and B sands, as shown in Figures 1 and 2. Its interpretation was that the A sand is geologically continuous between the A8-20 well and the 14-13 well. GNE also observed that pressure data for the two wells is very similar.

To allow Rustum the opportunity to produce its share of Glauconitic A sand reserves underlying fractional section 20 and to address the issue of drainage, GNE proposed that the Board designate fractional section 20 as a special gas DSU. Gas production rates from the A8-20 well would be limited by multiplying the maximum well productivity (the Qmax) by an area adjustment factor, being the ratio of the area of the fractional section to the area of a normal gas spacing unit (as set out in Appendix I). GNE also indicated that consideration could be given to designating a target area penalty factor, though it was not requesting such. GNE concluded that by allowing the A8-20 well to produce with the production rate appropriately restricted, all parties would be afforded the opportunity to produce their fair share of reserves.

3.3 Views of the Lessors

The section 21 Lessors were concerned about the potential for unfair drainage of reserves underlying section 21 by the A8-20 well. Though they were not opposed to Rustum being allowed to produce the A8-20 well,

they strenuously objected to the well being produced without the application of an off-target penalty factor determined using normal provisions in the Regulations.

The Lessors recognized two Glauconitic sands, the Glauconitic A and B sands, which they believed to be present over a well-defined area as shown in Figures 1 and 2. They submitted that Rustum had not demonstrated that the A8-20 well is in a separate Glauconitic reservoir. On the contrary, based on geological, pressure, and production data the Lessors concluded that communication probably exists between the A8-20 and 14-21 Glauconitic gas wells and the 14-16 and 6-21 Glauconitic oil wells.

In considering the appropriate target area for a special DSU comprising fractional section 20, the Lessors made reference to Board Decision D 87-18. They suggested that D 87-18 establishes two types of fractional sections:

(a) the first would be a fractional section sufficiently large for the normal 300-m setback target area rule to be applied and a target area would be available; and

(b) the second would be a fractional section which is so narrow that the normal 300-m setback rule would result in no available target area and the fraction would have to be pooled with an adjoining spacing unit to form a suitable gas well DSU.

The Lessors submitted that fractional section 20 is a fractional section of type (a) for which the normal 300-m setback target rule can be applied. The Lessors rejected the notion that Rustum had been so restricted by topography that it could not have drilled its well on the normal setback target for both gas and oil in fractional section 20. They argued that Rustum knowingly had taken the risk of being off target for gas when it drilled the A8-20 well and, in doing so, must bear the consequences of the A8-20 well being off target for gas under normal 300-m target setback provision. The Lessors concluded that the application of the off-target penalty would not make production from the A8-20 well uneconomic and would protect the interests of the Lessors.

3.4 Views of the Board

Any application to establish a special DSU where the area dimensions and drilling target provisions are intended to differ from those for a standard DSU requires that the Board view the application in the light of section 4 of the Oil and Gas Conservation Act, in addition to having regard for the provisions for standard DSUs set out in the Regulations. Within that framework, the Board has addressed the following matters:

(a) The eligibility of fractional section 20 as a special DSU.

(b) The appropriate target area provisions that should apply for the special DSU.

(c) The method of determining and the manner of applying any penalty or adjustment factors that would be used to restrict the rate of production from the A8-20 well.

(d) The delineation of the Glauconitic gas pool(s) penetrated by the A8-20 well. If the A8-20 well is in a single-well pool, it would be eligible for waiver of penalty/adjustment factors that would otherwise restrict production.

3.4(a) The Eligibilty of Fractional Section 20 as a Special DSU

In decision D 87-18, the Board concluded that in dealing with fractional sections where the size of the fractional section is not considerably smaller than the size of a normal gas DSU, and is such that the target area requirements set out in section 4.020(3)[1] of the Regulations can be applied, it is appropriate to establish a smaller than normal gas DSU consisting of the fractional section. In keeping with this, in that the size of fractional section 20 is such that the standard target area requirements for a normal gas DSU can be applied, the Board is satisfied that it is appropriate to designate fractional section 20 as a special DSU.

3.4(b) The Appropriate Target Area Provisions that Should Apply for the Special DSU

The Board agrees with the Lessors that the target area for a fractional section should be no closer to its DSU boundaries than that applicable for any normal gas DSU; that is, no closer than 300 m to the boundary of a section or 290 m where the boundary adjoins a road allowance. This is the principle which must be applied to protect the interests of offsetting owners of normal DSUs who are obliged to conform with those same target setback limits.

The applicant argued that the to-be-assigned target area should include the A8-20 well for environmental reasons because the well had been located on a previously constructed well site owing to steep terrain and it was impractical to endeavour to shift the well site along the

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1 Section 4.020(3) of the Regulations denotes that the target area for a normal gas DSU is within the central part of the DSU, having sides 300 m from the sides of the DSU and parallel to them.

hillside to get within a common oil and gas target. Additionally, the location of the existing well site had been agreed to by the surface owner. The Board is of the view that, had the applicant chosen to do so, it could have shifted the site so as to complete the well fully within the setback limit applicable for a normal gas drilling target. The applicant also pointed out that the fact that the interwell distance between its well and wells on sections 21 and 13 exceed 600 m is further reason for regarding the A8-20 well as being "on target". In the Board's view, however, only if the applicant had applied for and received approval for a special DSU with such a special target provision prior to drilling the well would this argument stand. The Board concludes that there is no valid reason for granting the special target provision requested by the applicant.

The Board finds that the special DSU for fractional section 20 should have gas target area dimensions as shown in Figure 3. The Board also finds that the A8-20 well is located some 56 m outside of the east boundary of that special target area.

3.4(c) The Method of Determining and the Manner of Applying Any Penalty or Adjustment Factor that Would Be Used to Restrict the Rate of Production from the A8-20 Well

Once a fractional section has been declared a special DSU for gas production and assigned a target area, the Board's general view is that the special DSU should be given the same considerations as a normal gas DSU. Should a well in the special DSU be located beyond the assigned target area, it follows that an off-target penalty should be applied to reduce the rate of production from the well by multiplying the penalty factor by the Qmax for the well. It is important to bear in mind that any well completed outside its target area would have a penalty factor value lower than 0.5000. Similarly, where a well in such a special DSU is within its target area but a concern about equitable drainage arises, the Board would likely consider restricting the rate of production from the well by applying an area adjustment factor. Specifically, the rate would be restricted by a factor, being the ratio of the area of the special gas DSU to that of a normal one-section gas DSU, multiplied by the Qmax. It is important to note that the area adjustment factor would always be higher than 0.3750.

Recognizing that an off-target factor would be lower than 0.5000, that an area adjustment factor would be higher than 0.3750, and that the Qmax is the reference base for determining equity for gas production, the Board believes that fractional section special DSUs should typically be subject to either an area adjustment or an off-target adjustment but not both, if an equity issue is raised.

On the above considerations, the Board finds:

(1) Applying the Board's standard off-target penalty formula, as set out in Appendix II, would result in a rate restriction factor of 0.3658 being applied against the Qmax rate for Glauconitic gas at the A8-20 well.

(2) Applying the area adjustment factor formula proposed by GNE, as set out in Appendix I, would result in a rate restriction factor of 0.5934 being applied against the Qmax rate for Glauconitic gas at the A8-20 well.

The Board concludes that equity can be satisfied by adopting the lower value of the above rate restriction factors, namely the off-target factor.

3.4(d) The Delineation of the Glauconitic Gas Pool(s) Penetrated by the A8-20 Well

The Board recognizes that if the A8-20 well were found to be completed in a single-well pool, any of the foregoing rate restrictions could be waived in view of the absence of the opportunity to create inequitable drainage. The Board has considered the evidence brought forward by all participants on the question of common or separate pools for the A8-20 well and offsetting wells. It finds that there are no unique geological factors to clearly demonstrate that the A8-20 well is in a separate single-well pool. On the contrary, the geological conditions described by all the participants lead the Board to conclude that the A8-20 well is likely in a common Glauconitic gas pool with other nearby wells, including those in sections 21, 27, and 28-39-28 W4M and section 13. While the Board acknowledges the existence of the two Glauconitic sands (the Glauconitic A and B sands), there is a probability that these sands form a common gas pool due to limited separation between them and therefore production from the sands need not be segregated.

The Board also finds that the pressure data available at this time does not demonstrate that the A8-20 well is in a separate pool, though it accepts that at some future time that might be demonstrated. Existing pressure data, along with available production data, does, however, suggest that the Glauconitic gas pool penetrated by the A8-20 well is not likely in communication with the oil reserves found at the 14-16 and 6-21 wells.

4 DECISION

On the basis of its findings, the Board has decided to grant a special DSU for fractional section 20 of township 39, range 28, west of the 4th meridian, for the production of gas from the Glauconitic Sand, with special gas target provisions as shown in Figure 3. Further, on the basis of its findings set out in this report, the Board has also decided that the rate of Glauconitic gas production from the A8-20 well shall be restricted by a multiplier being a target area penalty factor of 0.3658.

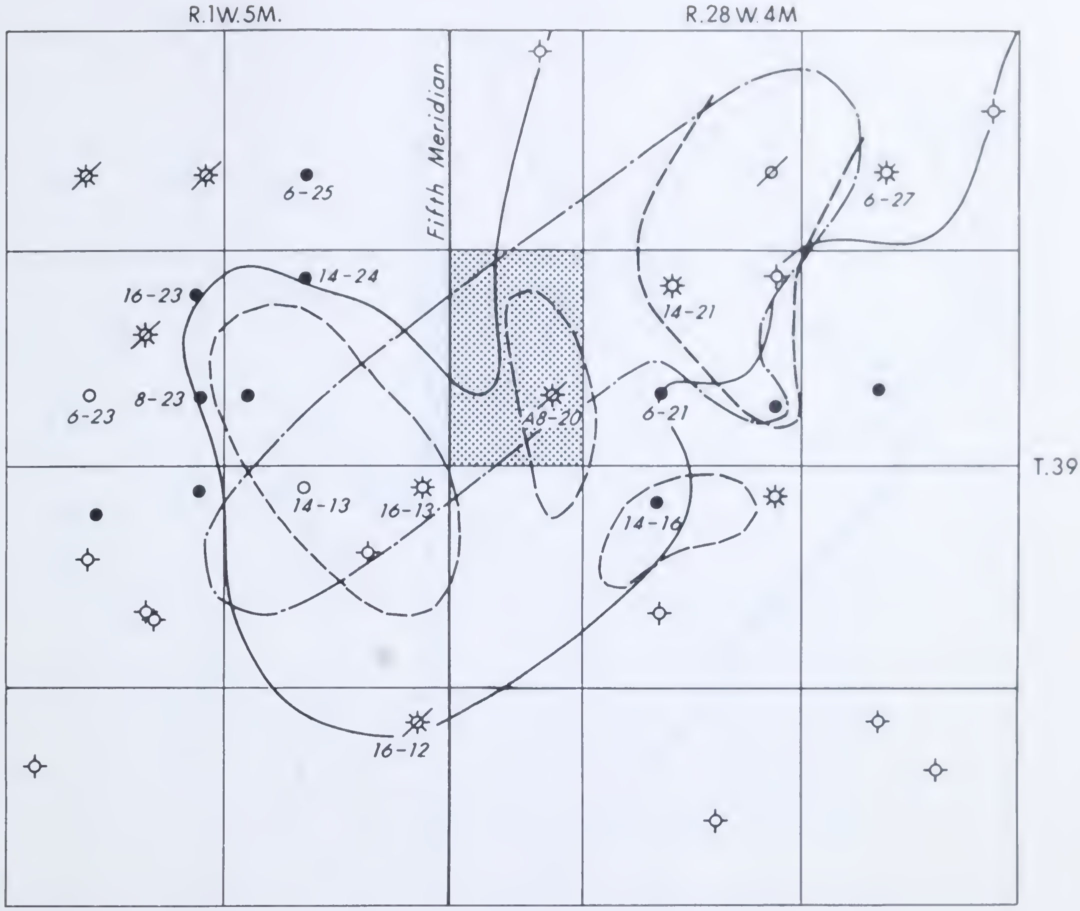
DATED at Calgary, Alberta, on 31 March 1989.

ENERGY RESOURCES CONSERVATION BOARD

N. A. Strom, P.Eng.
Vice Chairman

E. J. Morin, P.Eng.
Board Member

H. Antonio, P.Eng.
Acting Board Member



Capped gas
Flowing gas
Flowing oil
Suspended gas
Standing
Abandoned
Area of Application No. 880526
Rustum zero pay contour
GNE zero pay contour
Lessors' zero pay contour

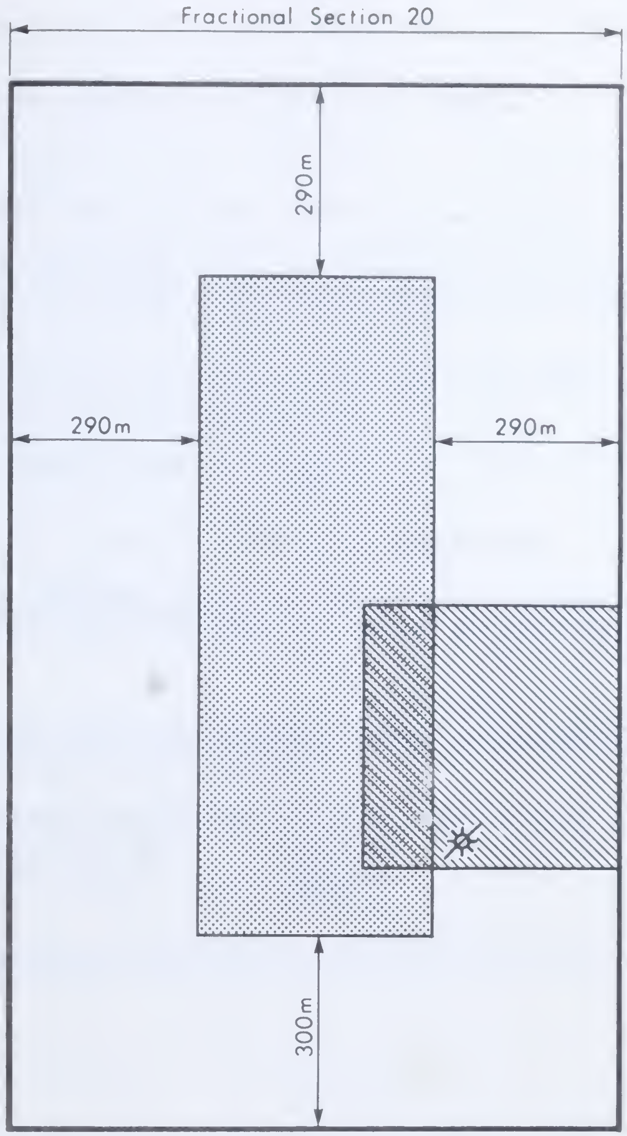
Well locations indicate Glauconitic Sand completions

FIGURE 1 GLAUCONITIC A SAND POOLS

Capped gas
Flowing gas
Flowing oil
Suspended gas
Standing
Abandoned
Area of Application No. 880526
Rustum zero pay contour
GNE zero pay contour
Lessors' zero pay contour

Well locations indicate Glauconitic Sand completions

FIGURE 2 GLAUCONITIC B SAND POOLS



A8-20 Well

Rustum proposed target area

Board-adopted target area

Board-adopted special drilling spacing unit boundary

FIGURE 3 BOARD-ADOPTED SPECIAL DRILLING SPACING UNIT AND TARGET AREA

APPENDIX I GNE'S PROPOSED RATE RESTRICTION FORMULA

(1) GNE's proposed rate restriction formula is as follows:

q = (qmax) x (Off-target Factor) x (Area Adjustment Factor)

where: q is the average rate allowed for production from the A8-20 well.

qmax is the rate calculated in accordance with section 10.300(1) of the Regulations.

Off-target Factor is $0.5 \frac{AB}{K}$ as set out in section 4.070 of the Regulations.

Area Adjustment Factor is the ratio of the area of the special DSU to the area of a normal gas DSU (256 ha).

(2) Using the above, the area adjustment factor for the A8-20 well is determined by the Board as follows:

Area of fractional section 20	= 151.9 ha, more or less
Area of a normal gas DSU	= 256.0 ha
Area adjustment factor	= $\frac{151.9 \text{ ha}}{256.0 \text{ ha}}$

The area adjustment factor for the A8-20 well is 0.5934.

APPENDIX II APPLYING THE STANDARD OFF-TARGET PENALTY FORMULA

(1) The standard 300-m target area setback requirement for a normal one-section gas DSU should also apply for a fractional section gas DSU.

(2) The standard off-target penalty formula for a normal one-section gas DSU is as follows:

Penalized Maximum Daily Allowable for a Gas Well
= (Qmax for the well) x (Off-target Penalty Factor)

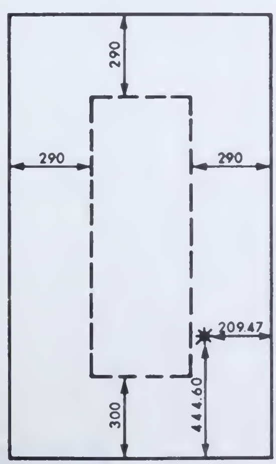
where: <u>Qmax</u> is a current maximum daily allowable calculated in accordance with section 10.300(1) of the Regulations. The Qmax rate is recalculated annually by Board staff.

<u>Off-target Penalty Factor</u> is $0.5\ \frac{AB}{K}$

such that:

- o A and B are the distances measured in metres from the uppermost point of intersection of the wellbore with the gas productive part of the producing pool to the two nearest boundaries of the DSU plus, where such a boundary adjoins a road allowance, 10 m.
- o Neither A nor B can exceed 300 m.
- o K is 300 x 300.

(3) Using the above, the off-target penalty factor for the A8-20 well is determined as follows:



Fractional Section 20

A = 219.47 m
(209.47 m + 10 m (Road Allowance))

B = 300 m

K = 300 x 300

Note: There are road allowances on the north, east, and west sides of fractional section 20.

✳ A8-20 Well
—— Drilling Spacing Unit Boundary
- - - Target Area Boundary

$$\text{Off-Target Penalty Factor} = 0.5 \, \frac{(219.47)(300)}{(300)(300)}$$

The off-target penalty factor for the A8-20 well is 0.3658.

NOTE: In the absence of a directional survey for the A8-20 well, the slope test was used to calculate an off-target penalty factor. Results from the slope test indicate that the wellbore at the top of the Glauconitic Sand is 444.60 m north and 209.47 m west of the nearest boundaries of fractional section 20.

ERCB

240-kV Transmission Line 946/947L

Ellerslie-East Edmonton

May 1989

ENERGY RESOURCES CONSERVATION BOARD
APPLICATION NO. 880953

May 1989

Published by

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ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

TRANSALTA UTILITIES CORPORATION
240-kV TRANSMISSION LINE
ELLERSLIE-EAST EDMONTON AREA

Decision D 89-2
Application 880953

1 APPLICATION AND HEARING

TransAlta Utilities Corporation (TransAlta) applied, pursuant to sections 12, 14, 17, and 18 of the Hydro and Electric Energy Act, for approval to construct and operate a double-circuit 240-kV transmission line, designated as 946/947L, from its Ellerslie substation 89S in the northwest quarter of section 27, township 51, range 24, west of the 4th meridian, to its East Edmonton substation 38S in the NE 31-52-23 W4M.

TransAlta submitted two alternative routes for consideration. The westerly Alternative 1, TransAlta's preferred route, would be 17.6 kilometres (km) in length while the easterly Alternative 2, located within the Edmonton and the Sherwood Park West Restricted Development Areas (RDAs), would be 21.1 km. The possible locations for the proposed facilities, and other key geographic features, are shown on the attached Figure.

The application was considered at a public hearing in Edmonton on 14-18 November 1988, with G. J. DeSorcy, P.Eng., J. P. Prince, Ph.D., and Dr. R. R. Orford, M.D., C.M., sitting. Written argument was subsequently filed with the Board to complete the proceeding. The dates for filing were 12 December 1988 for all parties and 23 December 1988 for TransAlta's response to matters raised by others in their final written argument.

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations Used in Report)		Witnesses
TransAlta Utilities Corporation (TransAlta)		
J. G. Friesen	Panel 1	W. Nieboer, P.Eng. N. J. Brausen, P.Eng. S. E. Hodgkinson, P.Eng. J. S. Rohrich, R.E.T.
	Panel 2	Dr. W. H. Bailey, Ph.D. Dr. J. S. Mandel, Ph.D. S. E. Hodgkinson, P.Eng.
Alberta Environment W. McDonald		F. Schulte, P.Eng.

THOSE WHO APPEARED AT THE HEARING (cont'd)

Principals and Representatives (Abbreviations Used in Report)	Witnesses
County of Strathcona No. 20 (The County) E. J. Walter, Q.C.	R. J. Powell, P.Eng. I. Evans, Reeve
Leduc-Strathcona Health Unit Dr. N. Bayliss, M.D.	Dr. N. Bayliss, M.D.
Hulbert Crescent Subdivision (Hulbert Crescent) J. R. Shaw R. M. Curtis	E. R. Schotte
Parents' Association, Colchester Elementary School (Colchester School) J. Kristensen	J. Kristensen S. Lindner P. Nissen C. Nissen Dr. S. M. Ross, Ph.D.
Sherwood Park Greenbelt Protection Association (Sherwood Park Greenbelt) P. H. Moxham	P. H. Moxham Dr. M. Adams, M.D. Dr. D. Brown, M.D. J. Pound, P.Eng. F. Gifford, P.Eng.
W. Hosford	W. Hosford
Edmonton Flying Club J. S. Rembish	J. S. Rembish
Interprovincial Pipe Line Company (Interprovincial) D. J. Jenkins	H. Sangster, P.Eng.
The City of Edmonton (The City) M. A. McAvoy	W. Cameron
Edmonton Metropolitan Regional Planning Commission (Planning Commission) P. Dickson	P. Dickson
Lehndorff Land Developments Inc. (Lehndorff) J. N. Agrios, Q.C.	K. Mackenzie
Industrial Power Consumers Association of Alberta D. E. Crowther	D. E. Crowther

THOSE WHO APPEARED AT THE HEARING (cont'd)

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Sherwood Park Fish & Game Association A. Boyd	A. Boyd
Trison Instruments Ltd. (Trison) L. L. Tachuk	L. L. Tachuk
Energy Resources Conservation Board staff M. Bruni J. Wilson, P.Eng. T. Chan, P.Eng. D. Novitsky B. Olliver	

1.1 Background

TransAlta made an earlier similar application (No. 830630) in 1983 proposing a double-circuit 240-kV transmission line along the route alignment identified in this application as Alternative 1, TransAlta's preferred route. A public hearing to consider Application No. 830630 had been scheduled for 25 October 1983. Prior to that hearing taking place, Alberta Environment advised TransAlta in writing that it would be necessary to locate the proposed 240-kV transmission line within the transportation and utility corridor of the Edmonton and Sherwood Park West Restricted Development Areas. TransAlta subsequently requested and received an adjournment of the hearing. Eventually it withdrew its application.

The project was deferred for several years as the general economic downturn resulted in a much slower than anticipated rate of electric load growth in northeast Alberta. The replacement application, currently under consideration, was filed on 2 June 1988.

2 ISSUES

The Board believes the following to be the major issues involved in the TransAlta application:

- Need for the proposed transmission line.
- Potential health effects of electric and magnetic fields (EMFs).
- Route for the proposed transmission line, to be discussed according to the following matters:

  a) Regulatory Considerations,
  b) Potential Effects on Health or Safety of Residents,
  c) Environmental Issues,

d) Economic and Technical Matters, and
e) Planning and Land Use.

3 NEED FOR THE PROPOSED TRANSMISSION LINE

3.1 Views of TransAlta

TransAlta listed three principal reasons respecting the need for the proposed line.

(i) Forecasts predict that in 1990/91 the northeast area electric load will exceed the capacity of the transmission system during single contingency outages.
(ii) Power transmission to the northeast area would be totally disrupted if coincident outages were to occur in circuits 904L and 908L between Ellerslie substation 89S and East Edmonton substation 38S.
(iii) A new double-circuit 240-kV line between the two substations, 89S and 38S, would realize savings from avoided transmission line losses of approximately $300 000 per year.

The above-mentioned northeast area load includes demand in the east and northeast sections of the city of Edmonton, Sherwood Park, Fort Saskatchewan, the Redwater area, and parts of northeastern Alberta, extending to the Bonnyville-Cold Lake area. Among the customers there are major petro-chemical plants, oil refineries, and oil-field services, all of which typically have a high load factor. The load in this area represents approximately 20 per cent of the province's total electrical requirements.

3.2 Views of the Interveners

The City of Edmonton supported the need for the proposed facility, stating that Edmonton Power's load makes up 42 per cent of the applicant's current northeast area load forecast.

In its submission, Lehndorff stated that there is no clear evidence the proposed line would be required. However, it did not indicate its reason for doubting the necessity of the proposed facilities.

No other interveners questioned the need for the proposed facilities.

3.3 Views of the Board

The Board agrees that the electric load in the northeast area will grow over time and that TransAlta's forecast of that growth is reasonable. No evidence to the contrary was presented at the hearing.

Having reviewed TransAlta's loadflow predictions for 1990, the Board also agrees that the present 240-kV transmission system requires reinforcement. The Board therefore accepts that a new 240-kV line between Ellerslie substation 89S and Edmonton substation 38S is necessary to provide the appropriate transmission capacity. The new

line will also increase the reliability of the system since it could prevent disruption of as much as 20 per cent of the province's total electric load in the event of coincident outages of 240-kV lines.

With respect to the applicant's view on savings from avoided transmission line losses, the Board notes that reduced line losses follow automatically when a new line is introduced between a power source and a load in a transmission network. Whether or not this results in net benefits depends on how much additional capital investment is required to improve efficiency. In this case, the savings from reduced losses can be achieved only with a significant capital investment that must be justified on other grounds. That investment notwithstanding, to the extent that there are savings from reduced losses they support the case for the new line.

4 POTENTIAL HEALTH EFFECTS OF ELECTRIC AND MAGNETIC FIELDS

4.1 Views of the Interveners

The concerns of members of the Colchester School Parents' Association arose primarily through their reading of various published studies and media material such as articles in newspapers or magazines and television documentaries. The interveners' panel included Dr. S. M. Ross, a researcher at the University of Calgary. His appointment at the University involves studying the cellular basis of bioelectrical healing phenomena. He presented a review of the literature in this field along with a summary of his work in progress.

Dr. Ross stated that it has been known for hundreds of years that electric and magnetic fields affect living organisms. Throughout this period, electricity has been applied to humans and animals, and effects observed. By the end of the 18th century there was a well-established field of electrotherapeutics, and books on therapeutic use of electricity were published. Dr. Ross said that there were people who died from electrotherapeutic treatments; however, the issue was confounded when it was discovered that sometimes heart attack patients would recover when electricity was applied. Dr. Ross believed that misuse of electricity for therapeutic treatments stemmed from a lack of understanding of electricity by physicians and biologists.

Dr. Ross submitted that electrical currents occurring naturally in living tissues are carried by ions in solution. He indicated that Dr. J. Wikswo of Nashville, Tennessee, had discovered there were circulating electric currents at the growing tip of a sample of cultured dendrite derived from goldfish retinas. He stated that Dr. Wikswo had provided theoretical and experimental evidence to support that the currents were carried by calcium ions. The current densities were in the order of 10 to 100 nanoampere per square centimetre (10^{-9} A/cm^2). He further stated that a number of electrical engineers modelling the kinds of electric currents induced in organisms by power lines found that current densities in the range of 0.5 to 100 x 10^{-9} A/cm^2 could be induced by power lines. He indicated that a typical power line electric

field of 10 kilovolts per metre (kV/m) might induce a current density of 15×10^{-9} A/cm^2 in organisms.

Dr. Ross described experiments by a number of researchers which had demonstrated that various species of animals can detect minuscule electric fields. He suggested that, if animals can detect minuscule extremely low frequency electric fields, there must be biological responses to the fields within the animals.

Dr. Ross also described a number of experiments where animal injuries were treated with electricity and where some corrections of injuries were observed. In other experiments, exposure to EMFs was shown to have an effect on cellular growth and composition in animals. The results of all the experiments led Dr. Ross to conclude that electric currents are important to the natural growth and healing of living organisms, although he is not sure whether they are the causes of the process.

With respect to his own studies, Dr. Ross submitted that he had examined the effects of static electrical fields on cells in tissue culture. The electric field strength which he used was equivalent to more than 10 000 kV/m in air. He observed that one response of cells to a uniform electric field is to align the long axis of each cell perpendicular to the direction of the current flow. However, he acknowleded that this response is not universal. As well, in response to TransAlta's cross-examination, he stated that he is aware that other researchers made specific comparisons between the effects of a static electric field at both 10-Hertz and 60-Hertz sinusoidal fields and did not find similar effects. He had also studied the possible migration of bone cells under the influence of a static electric field equivalent to more than 10 000 kV/m in air, and doubted that a 60-Hertz field could cause bone cells to migrate. His recent research has been concerned with the effects of EMFs on mammalian cells in vitro. He has been examining effects on proliferation of cells caused by extremely low frequency magnetic fields in the range of 100 to 11 000 milligauss. He submitted that under the influence of magnetic fields in the above range of magnitudes, he observed changes in cellular proliferation.

Dr. Ross concluded that effects on cells have been observed under the influence of both electric and magnetic fields. Notwithstanding that the magnitudes of both electric and magnetic fields applied were much higher than those associated with power lines, he submitted that more work should be done to determine whether or not there could be health effects due to power line fields. Colchester School, therefore, recommended keeping all new construction of power lines at a reasonable distance from populated areas until such time that the risks could be conclusively shown to be insignificant.

Sherwood Park Greenbelt submitted that, while available evidence on health effects due to power line EMFs might be inconclusive, it had provided definite grounds for concern. A great deal of research is now under way throughout the world on the EMFs health effect issue. The intervener believed that, while this type of research is continuing, the responsible course would be to take every opportunity to minimize public

exposure. It suggested that, since there is abundant land available for housing development in and around Edmonton, it would be prudent to place a moratorium on all development within at least 400 metres (m) of existing power lines until scientific research into the health hazards has been completed.

The County of Strathcona assembled a substantial collection of scientific articles on health effects due to EMFs. While it did not provide any expert witnesses to speak to health concerns, the County commented that it is concerned that there is no conclusive scientific evidence stating that there is no adverse health effect. Therefore, it opposed Alternative 2, in part, because there could be an unacceptable health risk to residents in the County.

Leduc-Strathcona Health Unit stated that a review of the literature suggested that the present expert knowledge of the effects of EMFs is inadequate and inconclusive. Because the effect of EMFs on children is not yet known, it is against locating the proposed line 80 m from Colchester School. Similarly, locating the proposed line 30 m away from two residences along Alternative 2 would be unacceptable. Although the same arguments for health concerns would hold in either Alternatives 1 or 2, the intervener contended that for Alternative 1, the extent of the separation between residential development and power lines should primarily be the choice of the developers.

Mr. J. R. Shaw and the residents of Hulbert Crescent Subdivision submitted that, with respect to health hazards, the evidence is not clear or conclusive in either direction. Sufficient evidence exists to demonstrate that the safety of power lines ought not to be taken for granted and further studies may well demonstrate that they are a substantial hazard to human health. However, unless the Board should come to the conclusion that the health hazards are so great as to nullify the need for the power lines, or unless the Board should conclude that there are mitigating circumstances which can reduce or avoid the health hazards, it is clear that some element of the population will be exposed to the health hazards no matter where the power line is located.

Lehndorff acknowledged that there are numerous submissions on the issue of health which expressed sincere concern. Notwithstanding the lengthy evidence that was presented, the intervener submitted that it is apparent that there is no conclusive evidence that there is a health hazard caused by transmission lines. The intervener further submitted that, if there is any doubt on this issue, or if there is any inclination on the part of the Board that there is a health hazard, then the transmission line should not be built anywhere at this time. Out of an abundance of caution and in view of the concerns that have been expressed, the intervener believes that the preponderance of evidence on health would result in a determination that any future transmission line be restricted to the RDA. The evidence indicates that, if there is a danger, it would be to those in immediate proximity to the transmission line as opposed to those who are at a considerable distance from it. Lehndorff submitted that it would be both prudent and responsible, in

the interests of long-term planning, to minimize these risks by restricting any transmission lines to the RDA.

4.2 Views of TransAlta

4.2.1 Electric and Magnetic Fields Associated with the Proposed Line

TransAlta submitted that EMFs occur naturally and are also produced wherever an electric current exists. Electric field strength is commonly measured in kV/m and magnetic field strength in milligauss. To put these units into perspective, TransAlta cited that the earth's EMFs are approximately 1.14 kV/m and 600 milligauss, respectively. Typical magnetic fields produced by common appliances are 1 to 25 milligauss. Within most homes, magnetic fields produced by household wiring and appliances fall in the range between 1/2 and 3 milligauss.

TransAlta stated that electric and magnetic field strengths due to a transmission line can be measured or calculated from computer models. The electric and magnetic fields generated by the proposed line would be the same along either of the alternative routes. However, because of the presence of adjacent 240-kV and 138-kV lines along Alternative 1, the fields at the edge of the right of way would be different from those of Alternative 2.

The electric field of a transmission line is directly related to the voltage of the line. Since transmission lines tend to be operated within a very small range of voltage variations and the geometry of the conductors seldom changes, the associated electric field pattern tends to be stable over time. TransAlta submitted that the maximum electric field strength anywhere within the right of way due to the proposed line would always be below 2 kV/m for either route.

The magnetic field of a transmission line is directly related to the current flowing in the conductors, the configuration of the conductors, and their height above ground. The line current depends on the load conditions. Under maximum line loading, the calculated peak magnetic field strength at the edge of the right of way, 1 m above ground, would be 77 milligauss and 42 milligauss for Alternative 1 and Alternative 2, respectively.

The strength of both electric and magnetic fields decreases proportionately with the increase in distance from a transmission line. At the Colchester School, which is approximately 80 m away from Alternative 2, the electric field strength due to the proposed line would be negligible. The associated magnetic field strength would be about 1/2 milligauss. At 400 m away from Alternative 2, both the electric and magnetic field strengths due to the proposed line would be negligible.

4.2.2 Biological Studies on Plausibility of Health Effects Due to Electric and Magnetic Fields of Transmission Lines

Sixty-Hertz electric fields can induce similar fields in a conducting object. However, the electric field strengths induced inside the conducting object are lower than those of the external fields by many orders of magnitude. Dr. W. H. Bailey, one of TransAlta's expert witnesses, submitted that human bodies are good conductors in comparison with air. Electric fields induced in a body are one hundred thousand to ten million times lower in strength than the external field to which the body is exposed. Thus the body effectively shields the interior from the external electric field.

The permeabilities of biological materials to magnetic fields are very similar to air, i.e., introduction of a biological subject to a magnetic field has a negligible effect on the field, and the magnetic fields inside the subject will be essentially the same as those outside the subject. Dr. Bailey submitted that scientific evidence suggests that biological effects from time-varying magnetic fields are not likely to occur until the currents induced within the body by the magnetic field approach those that are generated by nerves and other tissues. The World Health Organization has concluded that it would be unlikely to expect significant biological effects from exposure to magnetic fields which induce electric currents within the body that are below the level produced by the beating of the heart. The magnetic field strength has to be about 30 000 milligauss to induce the same magnitude of currents as those within the heart.

Experiments have been done with animals exposed to fields of much greater intensities than those produced by a transmission line. For example, in an experiment conducted for the New York State Power Lines Project, two strains of mice were exposed to a 50-kV/m electric field and a 10 000-milligauss magnetic field over three generations. No adverse effects were observed.

Dr. Bailey submitted that chances are very low for a person to be exposed in the normal everyday environment to 60-Hertz EMFs at the high intensities used in some of the experiments.

Dr. Bailey summarized all the information referred to by the interveners into four categories: (1) non-scientific materials, documentaries on television, and articles in magazines; (2) irrelevant studies; (3) laboratory studies; and (4) epidemiological studies. The last item, epidemiological studies, is discussed in Section 4.2.3.

1. Non-scientific Materials, Documentaries on Television, and Articles in Magazines

Dr. Bailey submitted that the media often take scientific information out of context and with no peer review. Reviewing the primary scientific information directly is therefore more instructive.

2. Irrelevant Studies

Several studies cited by the interveners included studies of microwaves, radio waves, and non-sinusoidal wave forms. These studies have no relevance to the 60-Hertz fields generated by power lines.

3. Laboratory Studies

Dr. Bailey summarized references cited by interveners and other additional laboratory studies dealing with 60-Hertz EMFs.

He commented that laboratory research can be designed to control variables precisely for investigating cause-and-effect relationships between agents and study objects. It is, thus, more powerful in determining causation than are epidemiological methods.

Dr. Bailey submitted that, in reviewing the large amount of literature on 60-Hertz fields, he used criteria established by the National Academy of Sciences in 1987 to assess the quality and the reliability of the studies. The Academy's review criteria are:

- The biological and engineering methodologies should be sound and appropriate for the experiment or study.

- A given experiment should be internally consistent with respect to the effects of interest.

- The experimental and observational techniques, methods, and conditions should be objective. "Blind" scoring (where the investigator making the observations is unaware of the experimental variable being tested) should be used whenever there is a possibility of investigator bias. "Double-blind" protocols (where neither the investigator making the observations nor the experimental subject is aware of the experimental variable being tested) should be used when the experimental subjects' perceptions may be unwittingly influenced by suggestions.

- The experimental techniques should be chosen to avoid effects of intervening factors such as microshocks, noise, corona discharges, vibration, and chemicals.

- Extreme care should be taken to determine the effective extremely low frequency fields, voltages, or currents in the organism.

- The sensitivity of the experiments should be adequate to ensure a reasonable probability that an effect would be detected if it existed.

- If an effect is claimed, the results should demonstrate it at an acceptable level of statistical significance by application of appropriate tests.

- The results should be quantifiable and replicable. In the absence of independent confirmation, the result should not be viewed as definitive.

Based on these criteria, and taking all the cited 60-Hertz studies into consideration, Dr. Bailey observed that 60-Hertz EMFs could not be identified as hazardous agents. Some studies which initially were presented as showing such effects could not be replicated. In others, it was shown that the initial experiment was not properly carried out. For example, a study by Dr. A. A. Marino failed to properly ground the cages of the animals being experimented upon. This caused the animals to receive microshocks when they tried to drink, which led to dehydration. Similarly, experiments concerning the transport of calcium ions presented particular problems with respect to the interpretation of data obtained with the chosen assay systems. Experiments designed to overcome these problems could not replicate the original findings.

Dr. Bailey gave particular attention to the issue of whether or not EMFs may cause cancer or contribute to cancer growth. Although this issue has been raised, it is not because any clinically detectable tumours have been observed in animals exposed to EMFs. In response to the Board's question, Dr. Bailey stated that to his knowledge there has been no detailed microscopic study of animal tissue structure which was subjected to long-term exposure to EMFs at multiple sites. However, he submitted that the New York State studies have shown that EMFs do not initiate cancer even in animals receiving very high levels of exposure to EMFs over several generations. There is no indication that mutagenic damage can be produced, nor is the ability of cells to repair damage from mutagenic agents impaired. Nor did a review of the literature uncover data that would demonstrate that these fields promote tumour development. The interpretation of the data, as reported by Dr. J. L. Phillips, that colon cancer cells grew faster when they were exposed to EMFs, has been dismissed by the scientists who reviewed this work for the New York State project. Moreover, subsequent experiments by Dr. M. M. Cohen employing even greater field intensities were unable to confirm Dr. Phillips' results.

Thus, according to Dr. Bailey, a review of the scientific literature has not implicated electric and magnetic fields as contributors to any step of the cancer process.

Dr. Bailey concluded that 60-Hertz EMFs from high voltage transmission lines would not be harmful to humans. He further stated that other expert scientific panels - namely, the Academy of Sciences, World Health Organization, American Institute of Biological Sciences, State of Florida Electric and Magnetic Field Advisory Commission, and New York State Public Service Commission - also concluded that there is no evidence to suggest that EMFs due to power lines pose a health hazard.

4.2.3 Epidemiological Studies on Possible Health Effects Associated with Power Lines

TransAlta's second expert witness, Dr. J. S. Mandel, testified that all the epidemiological studies on the long-term health effects of EMFs were of the observational type. There have been no long-term human experimental trials.

Observational studies are designed to identify and measure the degree of association between factors, such as occupational or environmental exposures, and occurrences, such as disease, injury, or death. Criteria for assessing whether or not a causal relationship exists between a factor and an occurrence include: (1) strength of association, (2) consistency, (3) coherence, (4) temporality, (5) biological plausibility, (6) dose-response, (7) absence of confounding, (8) absence of bias, and (9) specificity. Dr. Mandel believes that one should evaluate all the epidemiological data accumulated in an area of interest. If the data meet all the above-mentioned criteria, then causation is likely.

There are two types of observational epidemiological studies: (a) descriptive studies, which are considered hypothesis-generating, and (b) analytical studies, which are considered hypothesis-testing (and, therefore, generally preferable as a means to infer causation). In the EMFs literature, studies to date have been primarily descriptive. There have been a few analytical studies such as the Wertheimer study and the Savitz study.

Dr. Mandel submitted that the majority of the epidemiological studies fail to show any relationship between human exposure to EMFs and death from leukemia. He contended that the Wertheimer study, which has often been cited as showing such an association, was not done blind, i.e., the investigator, in assessing the exposure to EMFs, was aware of whether a house was occupied by a case subject who had leukemia or by a comparative control subject who did not have leukemia. The study was not based on actual measurements of magnetic field. Exposure of study subjects was characterized according to the wiring configuration and proximity of overhead power lines to their homes. It has been shown that exposure assignments did not correlate very well with actual measurements. Wertheimer did not conduct a match analysis in which a control subject is required to match each case subject. Furthermore, she was not consistent in using the addresses of the cases and controls, and did not properly analyse potential confounders.

Another study, by Dr. D. A. Savitz, which had also allegedly demonstrated an association, was criticized by Dr. Mandel on the basis that the author was able to interview only 70 per cent of his subjects and measurements of exposure were taken in only 36 per cent of the cases. Where exposure to EMFs was actually measured, no relationship could be observed between the disease and EMFs. The only statistically significant elevated odds ratios were in those analyses where the exposure was estimated using wiring configurations. However, with as many comparisons as were made with the data available, it is possible that such results were obtained purely by chance.

Dr. Mandel felt that the author's interpretation of the data was exceedingly generous.

Dr. Bailey submitted that Dr. Savitz's co-worker, Dr. H. Wachtel, has stated on many occasions that he does not believe that EMFs is the cause of the reported association. Dr. Mandel also submitted that with regard to all available occupational studies Dr. Savitz himself recently stated:

(1) "Unless electromagnetic fields are thought to be general human carcinogens, some other risk factor or study bias must be operating...," and

(2) "The use of usual occupation on death certificates or cancer registry records provides a very crude measurement of exposure. None of the studies of leukemia have validated the assumption that the men presumed to be exposed to such fields are, in fact, exposed. As noted by Bonell, electricians working in homes usually work on electrically dead equipment, while telecommunications engineers are exposed to levels of power frequency electromagnetic fields no higher than those found in an average home with a wide variety of domestic electrical appliances.

Several studies have examined the actual electric field exposures among power plant workers. Most workers received little exposure to electric fields and even exposed workers spent relatively little time in high level electric fields."

Another study was done in parallel with the Savitz study by Dr. R. G. Stevens, who found no correlation between wiring configurations or measured EMFs and leukemia in adults.

A study by Dr. L. Tomenius had also been cited to have linked leukemia with power lines. However, in this study a greater proportion of leukemia cases in the "exposed" group was among those who lived farthest from power lines, the reverse of what would be expected.

Dr. Mandel also submitted that the rate of increase of leukemia had not followed the rate of increase of electric energy consumption despite a remarkable seven-fold increase of per capita consumption from 1950 to 1985 in the United States. He contrasted this with the relationship between smoking and lung cancer where epidemiological studies over many years have consistently demonstrated a causal relationship and where the increase in lung cancer rate has parallelled the increase in cigarette consumption, both in men and women.

Dr. Mandel concluded that it is not possible to infer associations between EMFs and adverse human effect from the evidence which he had reviewed and from that cited by interveners.

4.2.4 TransAlta's Conclusion on Potential Health Effects Due to the Proposed Line

TransAlta, in summary respecting this matter, submitted that the scientific evidence does not indicate any adverse health effect from the level of EMFs associated with the proposed line. Notwithstanding, TransAlta recognized that the public's perception of risk might diverge significantly from the actual risk as determined by a scientific assessment of hard evidence or rational deliberation by experts.

TransAlta stated that it will continue to monitor results of high-quality scientific research related to the 60-Hertz EMFs health effect issue.

4.3 Views of the Board

The issue of biological effects from extremely low frequency EMFs is controversial. There are proponents on either side of the question as to whether or not EMFs from high-voltage transmission lines cause such effects among people who reside near them. In the course of this hearing, many participants contributed to the discussion of this issue.

The Board appreciates the applicant and the interveners making health experts available at the hearing. Their evidence, presented from both laboratory research and epidemiological perspectives on possible health effects due to EMFs, was extensive and informative.

The Board concurs with those participants in the hearing who stated that non-sinusoidal EMFs studies are irrelevant to the issue of possible biological hazards of 60-Hertz EMFs. Hence, although TransAlta submitted that the strength of the earth's magnetic field is significantly larger than that of a 240-kV transmission line, the Board notes that the earth's field is also non-sinusoidal and, therefore, has no direct relevance to the question of biological consequences due to power line fields.

A large number of experimental studies of the effects of EMFs on animals and some other organisms were cited in the submissions. Several studies were not directly relevant, even though they did show biological effects, because they involved the use of non-sinusoidal wave forms and/or high-frequency radiation that would cause biological effects through heating (e.g., microwaves) or through ionization (e.g., x-rays). None of the studies on 60-Hertz sinusoidal EMFs presented has shown harmful biological effects at levels likely to be found in the vicinity of a 240-kV high-voltage transmission line.

Several epidemiological studies have suggested an association between leukemia, and in some cases brain tumours, and occupational or environmental exposure to EMFs. Other studies, however, have failed to show any such association, and those showing effects have been criticized on methodological grounds. In addition, if leukemia and transmission lines were linked, the Board believes an increase should appear in the incidence of leukemia, parallelling the substantial

increase since 1950 in the use of electric power in residential areas. This has not occurred.

Both laboratory and epidemiological evidence concerning extremely low frequency EMFs has been reviewed by many independent authorities over the past several years, including the National Academy of Sciences (1977), World Health Organization (1984 and 1987), the American Institute of Biological Sciences (1985), the State of Florida Electric and Magnetic Fields Advisory Commission (1985), and the New York State Public Service Commission (1988). These authorities have consistently concluded that no adverse health effects have occurred from human exposure to environmental EMFs.

From the evidence presented at the hearing, the Board concludes that the electric field strengths that would exist at the edge of the right of way of either alternative are comparable to those that already exist along Alternative 1. Also, the magnetic field strengths that would exist at the edge of either right of way would be comparable to the ambient magnetic field strength produced by household appliances and wiring.

The Board also concludes that considerable biomedical research has been conducted to date and that it has not demonstrated harmful biological effects caused by 60-Hertz sinusoidal EMFs due to high-voltage transmission lines. Epidemiological and laboratory research currently under way, or to take place in the future, could modify this conclusion. However, while the Board supports the continuation of such research, it cannot base its decision concerning power line placement in the present case on speculation that health effects could possibly be demonstrated by future research.

The Board, therefore, concludes that there is no evidence of health effects of the proposed 240-kV transmission line that would justify denial of the application. On the same basis, the question of health effects should not influence its decision on the appropriate location of the line.

5 COMPARISON OF ALTERNATIVE ROUTES

TransAlta proposed two alternative routes which have been evaluated in accordance with the categories set out below:

5.1 Regulatory Considerations,
5.2 Potential Effects on Health or Safety of Residents,
5.3 Environmental Issues,
5.4 Economic and Technical Matters, and
5.5 Planning and Land Use.

Certain portions of the evidence apply to more than one factor. For ease of understanding, and to avoid repetition, the Board has dealt most extensively with the evidence in Section 5.2.

5.1 Regulatory Considerations

5.1.1 The Evidence

TransAlta stated that in the long term it favours Transportation and Utility Corridors (TUCs). It would have applied for only one route, within the RDA, if not for the availability of the existing transmission-line corridor, Alternative 1, with its concomitant economic, technical, and environmental benefits. TransAlta prefers retaining the RDA's utility corridor for future transmission lines, for which it does not foresee a requirement for at least the next 10 years.

TransAlta contended that placing transmission lines within the RDA is not mandatory. It noted Alberta Environment's testimony that either Alternative 1 or 2 would be acceptable.

Alberta Environment indicated that the Sherwood Park West RDA was established in the mid-1970s. The location of the RDA was determined by the ring road which had been established earlier by Alberta Transportation.

Plans for the TUC component of the RDA were first completed in 1979, with space allotted for major power lines, pipelines, municipal services, and other related facilities. Further refinements were made to the plans on a continuous basis. As part of the planning process, Alberta Environment retained the services of the consulting firm of Stewart Weir and Co. to assist in its final detailed planning of the northeast Edmonton corridor. A copy of this report completed in May 1985 and entitled "Edmonton Transportation/Utility Corridor Reassessment" was provided at the hearing by Alberta Environment.

Alberta Environment reiterated that this TUC component was designed to maximize the use of the corridor while providing usable space in areas that will eventually be surrounded by urban development.

Alberta Environment submitted that the province has acquired ownership of over 75 per cent of the lands in the TUC and is actively pursuing acquisition of the remaining properties. Alberta Environment concluded by indicating that either route, as proposed by TransAlta, would be acceptable.

The City of Edmonton indicated support for the TUC concept for locating transmission lines around Edmonton. It believes that all the parties endorsing the TUC concept should zealously endeavour to implement the concept. The City submitted that, since the RDA had been legally created and was in place, the subject transmission line should be placed in the RDA at this time so that the effect on future land use within the urban area would be minimized.

Lehndorff stated that the Edmonton RDA, which was developed in 1974, was designed with a TUC that could accommodate a ring road, transmission

lines, pipelines, and other utilities. It noted that the provincial government has acquired over 75 per cent of the affected lands in the Edmonton area. It predicted the provincial government would acquire all lands in the TUC and compensate all affected parties. Lehndorff submitted, therefore, that placing the proposed transmission line within the RDA would be consistent with the long-term plan for urban development.

The Planning Commission also supports the RDA concept. It, therefore, supported Alternative 2 for the proposed transmission line.

Colchester School stated that constructing a line along Alternative 2 would contravene the intent of the RDA. It believes that the RDA was established to prohibit any development detrimental to the natural state of the area. Colchester School also noted Alberta Environment's submission that either alternative would be acceptable.

Hulbert Crescent and Mr. Shaw stated that the proposed line should not be located along Alternative 2, since placing a power line in the middle of the RDA would sterilize much of it and limit the number of pipelines that could be accommodated. They further contended that placing a line in the RDA would be unwise, since an existing corridor already provides a suitable alternative. They stated that both TransAlta and The City of Edmonton had defined the existing right of way along Alternative 1 as a corridor because there are both power lines and pipelines in it, whereas there are no power lines in the RDA. Furthermore, they pointed out that articles written by Mr. Weir stated that existing corridors should be fully used before new ones are created. They also argued that the Minister of the Environment lacks the authority to order the locating of transmission lines in the RDA. Hulbert Crescent and Mr. Shaw, however, did indicate that approval of Alternative 1 would not preclude use of the RDA in the future.

The County of Strathcona stated that locating the proposed transmission line along Alternative 1 would comply with the provincial government's existing policy. It noted Alberta Environment's view that either of the proposed alternatives would fulfil corridor planning objectives. It also observed that the County's General Municipal Plan recommended that future power lines and pipelines should be encouraged to locate outside of residential areas. The County would, therefore, not support Alternative 2 within the RDA, believing it would conflict with existing residential development.

Mr. W. Hosford stated that an RDA should be a green belt where no construction takes place.

Sherwood Park Greenbelt does not oppose the TUC principle facilitating the orderly installation of utilities. It believes that simply because the RDA is there is not sufficient reason to place the proposed line in it. However, with proper planning, future lines could be incorporated into the corridor.

5.1.2 Views of the Board

The Board has reviewed the submissions regarding regulatory considerations respecting the use of the RDAs. The Board believes it is important to understand the intent of the TUC within the RDA. Alberta Environment's policy witness, Mr. Schulte, stated that the TUC has two roles: to accommodate utility and transportation facilities and to provide green space adjacent to urban areas. Furthermore, the witness indicated it is not the provincial government's intent to assign a priority to either purpose at the expense of the other; they are essentially equal. The Board notes the view of many interveners that the RDA is intended solely as a green belt, so that utilities installed in such a green belt would contravene that intent. However, the Board cannot concur, given that both legislation and government policy provide for the development of a TUC within the RDA.

At the same time, the Board observes that there is no existing legislation or government policy that would require the proposed line to be located in the RDA. Alberta Environment's policy witness indicated that approval of the line and its location were matters that should be decided by the Board. The Board agrees with this position as there are no regulations governing TUCs within RDAs that, by themselves, would dictate the decision on the application before it.

The Board's view is that route Alternative 1 is a de facto corridor, albeit non-RDA, and its use is not precluded if it is found to be in the public interest. It presently contains both power lines and pipelines that have affected future use of the land and carry visual implications for current and future residents. Similarly, route Alternative 2, in the RDA corridor, could be chosen if the public interest favoured that alignment, even though the most contentious portion of the route has no existing electric transmission lines. The Board will evaluate the evidence for both routes considering all relevant factors and will make its choice according to those factors. They are discussed in Sections 5.2 to 5.5 inclusive.

5.2 Potential Effects on Health or Safety of Residents

Potential effects on health associated with exposure to EMFs have been addressed in Section 4 of this report. The Board has concluded that the question of health effects should not influence the decision regarding the location of the line. Therefore, such effects will not be discussed further here and only evidence concerning other safety aspects of the proposed transmission line is dealt with.

5.2.1 The Evidence

TransAlta indicated that along Alternative 2 there are nine residences within 100 m of the centre line of the transmission line, mainly those in the Hulbert Crescent subdivision. Along Alternative 1 there is only

one such residence. Residents of Sherwood Park backing onto the RDA would be located approximately 400 m and Colchester School would be some 80 m from Alternative 2.

Hulbert Crescent objected to Alternative 2, since the proposed line would pass directly over the residential subdivision. It had concerns about the safety of children who could climb the towers, the danger of shocks from electric currents induced in fences, and the danger associated with the use of herbicides to control vegetation on the right of way.

Colchester School noted that the school boundary and playground are less than 80 m from the alignment of Alternative 2. It considered the close proximity of the proposed line very dangerous to children flying kites or playing near the towers. Moreover, if Alternative 2 were approved, the proposed line would partially surround the school on three sides. Thus, should the towers fall during a severe storm, the school could be isolated from all access routes.

Sherwood Park Greenbelt also voiced concerns over the safety of proposed Alternative 2, citing the possibility of lines falling and children flying kites or climbing towers, as well as the possibility of collision by hot air balloons and small aircraft. If locating the proposed line in the existing right of way within Alternative 1 is considered hazardous to school children, conceptual plans for schools in the area could be modified.

Having regard for the proposed alignment of Alternative 2, which it notes would enclose Colchester School on three sides 80 m away, as well as pass through Hulbert Crescent subdivision and directly over the Edmonton Gun Club, the County was concerned about the safety of all persons along this route.

The County also stated that the alignment of Alternative 2 would be criss-crossed by 18 pipelines at 7 crossing points. It was concerned about the possible corrosion of pipelines because of the flow of electric current induced by the proposed line, believing that a pipeline leak could be lethal to people within 300 m of the pipeline. It further stated that placing the proposed line between the two existing transmission lines along Alternative 1 would not increase the potential safety hazard to the area.

Lehndorff indicated that residential development would be backing onto the transmission line right of way along Alternative 1. It submitted that there would be additional risk, albeit small, in adding a third line between two existing lines.

In response to the suggestion that the towers for the proposed line be fenced off, TransAlta said that fencing would not be necessary because the towers are designed in such a way that they are not easily climbed. TransAlta cautioned that flying kites or other devices in the vicinity of the line would not be prudent, regardless of where it is located.

With regard to some interveners' concerns about the possibility of electrical shocks from fences near the lines, TransAlta stated that the fences are always permanently grounded as a matter of practice to eliminate any induced charge. TransAlta agreed that transmission towers could topple in severe storms, but claimed the structures and conductors would fall within or in very close proximity to the right of way. Therefore, it believed that the towers or conductors would not fall on the Colchester School. Moreover, should a tower collapse, or a conductor snap, the line would automatically be de-energized within milliseconds by built-in protection control devices.

Mr. Hosford has operated his airstrip, located in the NE 1/4 17-52-23 W4M, for 20 years. He indicated that there are 20 to 30 airplanes usually parked at the airstrip. He stated that constructing a transmission line along Alternative 2, which would be located 900 m to the east of his airstrip, would be hazardous to the numerous aircraft using his facility, particularly since the majority of the aircraft would be flying in a westerly direction to land. He agreed that the proposed line along Alternative 2 would fall within guidelines established by Transport Canada; however, he proposed avoiding a new aviation hazard by locating the new line along Alternative 1.

The Edmonton Flying Club submitted that it regularly uses the Hosford airstrip for RCMP Highway Patrol as well as training. It supported Alternative 1, believing that a transmission line along Alternative 2, just 900 m away from the airstrip, would be a hazard to pilots flying at low altitudes or in poor visibility.

The County also stated that, since the Hosford airstrip would be only 900 m away from Alternative 2, a transmission line along this route could pose a hazard to all air traffic using the airstrip.

TransAlta stated that Mr. Hosford's airstrip is located approximately 1600 m from Alternative 1 and about 900 m from Alternative 2. It submitted that the airstrip is not licensed and, even if it were, both routes would comply with Transport Canada's regulations regarding licensed airstrips. In any event, TransAlta would install aircraft warning markers on the overhead shield wires of the transmission lines if Alternative 2 were chosen.

Interprovincial presently operates a tank farm located in the SE 1/4 5-53-23 W4M. It opposed Alternative 2 because it would interfere with future development of a tank farm in the NW 1/4 32-52-23 W4M, adjacent to its existing facilities. Interprovincial stated that the Electrical Protection Act requires a minimum distance of 15 m between the centre line of a 240-kV line and the firewall of a storage tank so that the tanks could not be damaged should a tower collapse. To facilitate operation, maintenance, and emergency access, Interprovincial submitted that a 45-m setback from the centre line would be more appropriate.

In response to Interprovincial's contention that a 45-m setback would be required between the centre line of TransAlta's transmission line and its storage tanks, TransAlta stated that a 15-m setback from the proposed line would meet the Electrical Protection Act minimum distance requirements.

5.2.2 Views of the Board

The Board has carefully considered the evidence presented at the hearing with respect to safety of the proposed transmission line. It has reviewed the evidence to determine if the safety concerns are such that either route should be denied, and, if not, whether safety concerns suggest that one route should be favoured over another.

An initial consideration is the number of people who would be exposed to some potential risk for each of the alternative routes. There are nine residences within 100 m of Alternative 2; other facilities, such as the Edmonton Gun Club and Colchester School, are in close proximity to that route. Currently, there is only one resident within 100 m of Alternative 1 but, in future, a large number of residences in close proximity to that route are likely.

With respect to the planned development along route Alternative 1, some interveners commented that future residents along that route would have a choice as to whether or not to live in the vicinity of the proposed line, whereas residents along Alternative 2 would not. The Board gives some weight to this argument, particularly as it relates to aesthetic concerns, but notes that Lehndorff has already made a commitment to develop the area along Alternative 1, and Lehndorff's interests must be balanced against those of residents living near Alternative 2. More importantly, with respect to the issue of safety under discussion here, the Board believes it has a responsibility to weigh appropriately the interests of future residents along Alternative 1 against the interests of current residents along Alternative 2.

The Board acknowledges the concerns of the interveners regarding the possibility of towers falling, and the danger to children climbing towers or flying kites in the vicinity of the the towers. The Board agrees with the applicant that there is minimal danger of children climbing on the towers, as they are designed in such a way as to minimize the risk. Therefore, fencing off the towers is not warranted. The Board also agrees that kite flying in the vicinity of any electrical transmission line is imprudent, but recognizes that there can be no guarantee that such would not happen. It does not believe that the risk of a kite-related accident would be significantly greater on one route than the other, nor that it should deny the application because there is a very small risk that such an imprudent act could cause an accident.

With respect to falling towers, the Board notes that it would take enormous force to cause steel towers such as those proposed to collapse. In either location, in the unlikely event that towers did fall, they

would fall primarily within the right of way and represent little threat to structures outside of the right of way. Also, the conductors would be immediately de-energized.

Alternative 1 already has two sets of towers, one set of 240-kV steel towers similar to those proposed in the application and another set of 138-kV single wood-pole structures. The addition of a third set of towers between these two sets could add a new element to the risk of tower failure. That is, if one of the new towers ever did fall, because of some disastrous event, there is some risk that the falling tower could affect other towers adjacent to it. Again, however, any falling towers would primarily remain within the right of way, posing little danger to structures outside of the right of way.

In any case, the Board believes that the risk of towers falling, even in the event of a natural disaster, is very small and is not sufficient reason to deny the application. Moreover, since there is no evidence to suggest that one route is more prone to natural disaster than the other, nor that the effects would be drastically different, this factor does not strongly favour either route.

In summary, regarding the proximity of the proposed line to residents, the Board recognizes that there are potential safety hazards associated with living in close proximity to transmission lines, as indeed there are such hazards associated with many other aspects of a mobile, industrial society. The risk these hazards pose to the population must be low enough to be acceptable to society. Hazards that can be avoided by the reasonable exercise of individual judgement and responsibility may be acceptable. In the case at hand, and having regard for the existing small population along Alternative 2 and the likely future larger population along Alternative 1, the Board believes that the risks of either alternative are very low and comparable to those associated with many other lines in the province as well as those of other kinds of industrial activity essential to the functioning of modern society. The Board judges these risks low enough to allow the project to go ahead if other issues are satisfactorily resolved. Also, in this case the Board sees no compelling reasons to favour one route over the other on grounds of safety of people in the area.

Regarding Interprovincial's concerns relating to safety in the vicinity of the future oil tank farm, the Board believes that adequate transmission line setback requirements are provided for in the Electrical Protection Act. In this respect, Alternative 1 has a slight advantage over Alternative 2, since no such facilities presently exist along that alignment.

With respect to pipelines, the Board believes that, with appropriate mitigation, there would not be a safety hazard created by placing the proposed line near existing or future pipelines on either route.

The Board acknowledges Mr. Hosford's concerns regarding the potential hazard to his airstrip. However, even if the airstrip were licensed and

the glide path protected by Transport Canada's regulations, both proposed routes would be acceptable under those regulations. As well, TransAlta has indicated that it would provide warning markers on that portion of Alternative 2 in the vicinity of the airstrip. The Board does not believe that either alternative creates an unacceptable hazard to the users of Mr. Hosford's airstrip; however, the potential risk may be somewhat less along Alternative 1 because of greater separation distance.

The Board's overall conclusion regarding safety is that both routes are acceptable. Although neither route has a clear safety advantage, the non-RDA route, Alternative 1, is somewhat more preferable.

5.3 Environmental Issues

5.3.1 The Evidence

Sherwood Park Greenbelt submitted that locating a transmission line in the RDA would create an unpleasant view for residents of Sherwood Park and others in the area, as well as for people using the main highway to Sherwood Park from Edmonton. In comparison, since power lines presently exist along Alternative 1, the additional visual consequences would be minimal.

Hulbert Crescent and Mr. Shaw were concerned about the visual effect of the proposed line since residents of Hulbert Crescent would have one or two towers located in the middle of their subdivision.

The County indicated that placing the proposed line on Alternative 2 would have a negative visual effect on entrances to the County at the Sherwood Park Freeway and Baseline Road.

Lehndorff indicated that placing a third line within the existing narrow right of way in the Meadows area would prevent fully effective landscaping between the towers. It submitted that a new line on Alternative 2 would have 5 to 6 towers per mile. In contrast, three lines in Alternative 1 will have 27 towers per mile, which it believes would compound the visual impact of the transmission lines. It stated that the Meadows area will eventually house approximately 50 000 people, 15 000 of whom will live closer to the proposed Alternative 1 than anyone living in Sherwood Park will be to Alternative 2.

The City of Edmonton indicated that the proposed line along Alternative 1 would conflict with a walkway and landscaping that are planned for the right of way upon which the new line would be located. The City acknowledged that it would still be possible to construct a walkway and plant trees. However, because the height of trees would be restricted, they would not reduce the visual effect of the transmission line.

Witnesses for both Lehndorff and the City suggested that the visual impact of a third line along Alternative 1 would be considerable, and perhaps close to that resulting from a new line along Alternative 2.

TransAlta indicated that locating the transmission line along Alternative 1, between existing transmission lines, and placing new structures adjacent to existing structures, would minimize the visual impact. TransAlta noted the concurrence of Lehndorff's expert witness that Alternative 2 would have more of an incremental aesthetic impact than Alternative 1. It also indicated that Alternative 1 would not interfere with the ability of Lehndorff to landscape or incorporate the right of way as part of an open space with bicycle paths or walkways.

Colchester School indicated that the alignment of the proposed Alternative 2, which is about 3.5 km longer than Alternative 1, would affect more residences and mar the appearance of the area. Colchester School further indicated that, if Alternative 2 were approved, a number of parents might withdraw their children from the school, with the possible result of closure of the school. This would, in turn, result in the loss of an important social, cultural, and recreational centre for the community.

The Sherwood Park Fish and Game Association contended that a transmission line along Alternative 2 would harm the wildlife habitats in the area. It quoted studies stating that "Transmission lines are the major cause of collision-related bird mortality." It also noted that Alberta Environment's stated objective of the RDA is the protection of the natural environment. A number of other interveners agreed that the line would have a detrimental effect on waterfowl flying into several waterbodies in the area.

TransAlta indicated that, along Alternative 2, the line would pass 60 m south and west of Base Line Slough, a staging and production area for waterfowl. The applicant discussed the potential impacts with Alberta Fish and Wildlife, who indicated the effect of the line on waterfowl using the slough would be minimal.

5.3.2 Views of the Board

The Board has evaluated the potential for environmental damage resulting from the line along each of the proposed routes. On the basis of evidence at the hearing, the Board believes the two things which could be most affected would be wildlife and the appearance of the respective landscapes.

The Board recognizes the position put forward by Lehndorff that the cumulative effect along Alternative 1 of placing a third line between two existing lines could be quite significant. The potential impact of the third line is difficult to visualize but some visual complexity is inevitable. TransAlta has proposed erecting the new towers adjacent to the existing steel towers, partly to mitigate the visual impact, but this may enjoy limited success.

At the same time, the Board believes that the addition of such a line to the existing corridor along Alternative 1 would be less visually disruptive than placing it in a green field situation as presently exists along Alternative 2. Also, because Alternative 1 is shorter than Alternative 2, there would be fewer towers and less line length. Therefore, all other things being equal, visual impact should also be less for Alternative 1.

The evidence suggests that in the future (10 years or more) another line might be required through this area, in which case the RDA route could well be chosen. In that event, the visual benefits from choosing Alternative 1 over Alternative 2 could well have a finite time limit. Eventually, both routes could be affected. Nevertheless, the Board believes there is an advantage in chosing Alternative 1 over Alternative 2 in terms of visual impact at the present time.

As to wildlife, especially waterfowl, the Board does not believe the proposed line will have a significant effect. To the extent that there is a potential for impact, Alternative 1 is preferable since the RDA is closer to a number of sloughs.

In comparing the visual and ecological issues associated with the two routes, the Board finds that Alternative 1 is preferable to Alternative 2, although neither route would be denied on these grounds alone.

5.4 Economic and Technical Matters

5.4.1 The Evidence

TransAlta stated that the estimated cost of Alternative 2 (21.1 km in length) would be approximately $7 million compared to $5.5 million for Alternative 1 (17.6 km long), a difference of $1.5 million.

Colchester School, Mr. Shaw, and the County, noting this additional cost, contended that there is no justification to spend an additional $1.5 million to construct a line along Alternative 2. They further noted that there are a number of additional cost factors, e.g., final alignment of the transmission line in the vicinity of the Edmonton Gun Club, existing residents, and pipelines in place, which may further increase the cost of Alternative 2.

Lehndorff indicated that, when the Government of Alberta acquires all remaining land in the Sherwood Park RDA, TransAlta will have no land cost for Alternative 2. Thus the cost will be reduced by $712 000 and the net cost difference for the two routes would be about $800 000. Lehndorff submitted this would be a small price to pay in order to implement the RDA concept.

Trison indicated concern that the proposed line along Alternative 2 would interfere with electrical equipment used in its research and development program. It considered shielding its building; however,

this would be costly and not an effective solution. Trison therefore supported locating the line along Alternative 1. Colchester School and Sherwood Park Greenbelt supported Trison's position and also expressed the view that a line along Alternative 2 would interfere with telecommunication equipment.

TransAlta indicated that it did not believe that Alternative 2 would interfere with existing communication facilities in the area. Edmonton Telephones and Alberta Government Telephones had advised TransAlta that both transmission line routes would cause minimal problems with their facilities, and very little mitigation would be required. TransAlta stated that the line would be constructed and maintained so as to keep interference with radio and television reception within limits acceptable to Communications Canada. In response to the concerns of Trison, TransAlta stated that its proposed transmission line would not interfere with Trison's equipment for electronic measurement because the electric and magnetic field levels attributable to the proposed line at the east boundary of the RDA would be negligible.

5.4.2 Views of the Board

With respect to the estimated costs of the proposed facilities as presented by TransAlta, the Board generally accepts the estimates as reasonable and within TransAlta's normal limits of accuracy. It notes Lehndorff's contention that, once the Government of Alberta has acquired the necessary lands within the RDA, TransAlta will not be obliged to pay anything further for the use of those lands, so that the costs of Alternative 2 would be reduced by $712 000. On this matter, the Board's view is that the land will be purchased by the Government of Alberta, whether or not the transmission line is located within the RDA. Therefore, costs associated with land purchases should not be considered in the comparison with Alternative 1. However, even without the land costs assigned to Alternative 2, Alternative 1 would be less expensive by some $800 000 and is therefore preferable.

The Board also notes that a number of interveners raised the question of cost contingencies that might accumulate along either route. Their evidence implied that as much as one million dollars could be added to the estimated costs of Alternative 2. On this matter, the Board observes that Alternative 2 is not as well defined as Alternative 1. The transmission line component within the TUC exists in concept only and has not been actually surveyed. If Alternative 2 were to be selected, the Board believes the component might have to be adjusted to allow construction while accommodating other land uses. This could increase costs to the upper limits of the estimates. This greater uncertainty in the cost estimates for Alternative 2 as compared to Alternative 1 serves to accentuate the higher cost for Alternative 2.

The Board agrees with TransAlta that the proposed transmission line on either route would cause minimal problems with existing communication facilities. The Board notes that TransAlta is required to construct and maintain its line so as to keep any telecommunication interference

within limits acceptable to Communications Canada. In considering Trison's concerns, the Board notes TransAlta's evidence that the EMF strengths of the proposed line would be so negligible that they would not interfere with Trison's equipment. The Board believes that this would be the case. However, if there were any question of interference, the Board would be prepared to investigate the matter further with Trison, TransAlta, and the Federal Department of Communications, and to require any necessary action.

In summary, in evaluating the economic and technical issues, the Board's view is that either route is acceptable but the non-RDA route is preferable.

5.5 Planning and Land Use

5.5.1 The Evidence

TransAlta indicated that Alternative 1 is approximately 17.6 km in length and would be located on an existing right of way. Alternative 2 would be approximately 21.1 km in length, with only 5.2 km located in an existing right of way. Although the latter route would follow RDAs for much of its length, new right of way would be required, either from the Crown or from private landowners.

Most of the interveners favouring Alternative 1 pointed to the additional length of Alternative 2, with the need to obtain additional right of way, as a disadvantage of that route.

Lehndorff, on the other hand, stated that the right of way for Alternative 1, through the Meadows area, is narrower than that recommended in the Weir report. It argued that to allow three lines adjacent to one another in such a narrow right of way would depart from proper planning and result in an unacceptable intensification of lines.

With respect to current and planned land use, Lehndorff stated that Alternative 1 would significantly interfere with future development of the Meadows subdivision. It stated that planning for the Meadows had commenced in 1982 and that it would ultimately accommodate approximately 50 000 people. Lehndorff argued that, since the RDAs had been provided to accommodate electric transmission lines and other utilities, and since future lines will have to follow such routing in any case, placing the currently proposed line in the RDA along Alternative 2 is appropriate.

The City of Edmonton supported Lehndorff in this regard, contending that Alternative 1 goes through an area designated for urban and residential growth. A transmission line along this route would interfere with plans for land use and be an eyesore. The City indicated that the Meadows area structure plan had been designed to recognize constraints imposed by the two existing lines, but not a third line. The City concluded that the line should be placed in RDAs created for that purpose, rather than through a planned residential area.

constraint precluding the use of Alternative 2, as future development within the RDA could be accommodated with adequate planning. Nevertheless, in comparing the two proposed routes, the Board believes that there are some advantages to Alternative 1, since a well-defined right of way presently exists for much of the route. This right of way has already figured in the planning and designing of future development along Alternative 1.

Regarding Interprovincial's concern about potential interference with a future tank farm, the Board agrees with TransAlta that approximately 10 acres, not 18 acres, could be sterilized. Although a transmission line along Alternative 2 can co-exist with a facility such as a tank farm, locating the line along Alternative 1 would be preferable.

Several interveners contended that the proposed line would decrease property values in areas adjacent to the line. In this regard, there was not sufficient evidence to support a prediction of reduced property values on either route. The Board notes that some interveners were concerned with interference in farming operations. The Board does not believe that building the line on either route would cause major interference in this regard.

In summary, the Board does not believe that any of the issues or concerns raised about planning or land use by the participants were so serious as to cause denial of either of the routes. In comparing the two proposed routes, the Board concludes that Alternative 1 is slightly preferable with respect to planning and land use.

6 CONCLUSION REGARDING THE PROPOSED ROUTES

It remains to be considered whether the cumulative concerns regarding safety, risk to the environment, costs, and planning and land use are sufficient to cause the Board to deny the application or, failing that, to choose one route over the other. The Board believes that the sum of all concerns raised by interveners does not provide sufficient grounds to deny the application. The potential adverse effects of either route are outweighed by the overall benefits of constructing the new 240-kV transmission line between TransAlta's Ellerslie substation and its East Edmonton substation.

As to the choice of routes, the Board notes that almost all of the comparisons discussed earlier either favour Alternative 1 or are neutral with respect to location. The Board therefore concludes that the westerly Alternative Route 1, TransAlta's preferred route, is the most appropriate choice.

7 DECISION

The Board is satisfied that the need for the proposed line and the benefits that would result from it outweigh any negative consequences associated with its construction and operation. The Board has therefore decided:

1. To approve construction of a 240-kV double-circuit steel tower transmission line, to be designated as 946/947L, from Ellerslie substation 89S to East Edmonton substation 38S, along the Alternative 1 alignment as described in the application.

2. To approve the connection of the two 240-kV transmission circuits to the Ellerslie substation 89S.

3. To approve the connection of the two 240-kV transmission circuits to the East Edmonton substation 38S.

4. To approve other related alterations.

Although the Board, as indicated in this report, has assessed the TransAlta application in detail and is satisfied that it should be approved, it believes it must deal with one other aspect of the matter before it. In its original intervention, The City of Edmonton had requested that the Board issue an order that Edmonton Power share in the ownership of the transmission line applied for by TransAlta. After discussion with Board staff, Edmonton Power withdrew that portion of its intervention.

Subsequent to the subject hearing, Edmonton Power applied to the ERCB for an order requiring TransAlta to provide a 50 per cent ownership in an existing transmission system, the 500-kV system between Keephills and Ellerslie. TransAlta argued that the Act does not authorize the Board to order the transfer of ownership in a transmission system. The Board addressed that jurisdictional matter and received written argument from TransAlta, Edmonton Power, and the Industrial Power Consumers Association of Alberta.

The Board had not, prior to the 500-kV Keephills-Ellerslie case, dealt with a specific request for an order directing a transfer of ownership. It had, therefore, never provided an opportunity for comment, nor received a challenge, as to its jurisdiction regarding the ownership question.

After considering the written arguments of interested parties, the Board, in a Memorandum of Decision issued 1 May 1989, concluded that it was not satisfied that section 17(2)(e) of the Act authorizes it to order the transfer of ownership of all or part of an electric transmission system.

On the basis of what has recently transpired, the Board concludes that had Edmonton Power not withdrawn a portion of its intervention, the question of ownership of the line would have been dealt with at the subject hearing. Since this did not occur, the Board recognizes that Edmonton Power may wish to pursue the matter at this time.

For this reason, the Board will not proceed with a request for Ministerial approvals, or the issuance of the ERCB approvals, until

Edmonton Power has had an opportunity to consider whether it believes its situation was prejudiced by the above described sequence of events, and to make related representations to the Board.

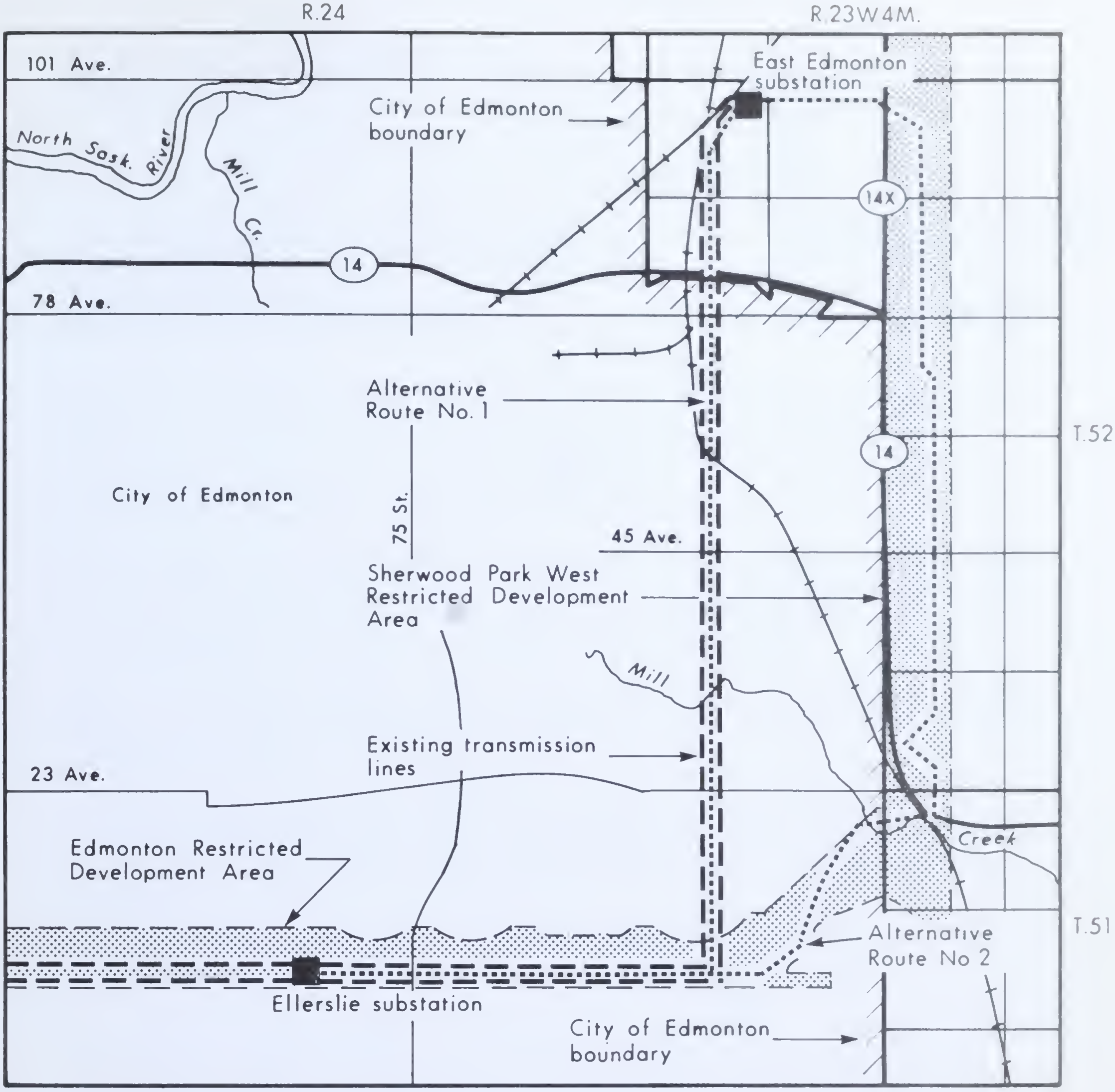
DATED at Calgary, Alberta, on 10 May 1989.

ENERGY RESOURCES CONSERVATION BOARD

G. J. DeSorcy, P.Eng.
Chairman

J. P. Prince, Ph.D.
Board Member

Dr. R. R. Orford, M.D., C.M.
Acting Board Member



PROPOSED TRANSALTA EAST EDMONTON TRANSMISSION LINE 946/947L
Application No. 880953
TransAlta Utilities Corporation

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

THE CITY OF EDMONTON (EDMONTON POWER)
JOINT OWNERSHIP
240-kV TRANSMISSION LINE
ELLERSLIE - EAST EDMONTON AREA

Memorandum of Decision
Application 880953

TransAlta Utilities Corporation, by Application 880953, requested Energy Resources Conservation Board approval to construct a double-circuit 240-kV transmission line in the Ellerslie - East Edmonton area. Following a public hearing of the application, the Board decided to approve construction of the line and issued Decision D 89-2.

In Decision D 89-2 the Board also indicated that it would not proceed with a request for Ministerial Approvals, or the issuance of ERCB approvals, until Edmonton Power had an opportunity to make representations relating to the ownership of the line.

In a letter dated 31 May 1989, the City of Edmonton, pursuant to section 17(2) of the Hydro and Electric Energy Act, Chapter H-13, R.S.A. 1980, requested an order

> "That the City be an owner of an undivided 50% interest in the 240-kV double-circuit steel tower transmission line designated as 946/947L from Ellerslie substation 89S to East Edmonton substation 38S."

TransAlta provided comment on the City's request, the City provided comment in response, and TransAlta did likewise.

The Board has made a careful review of the Act and the comments provided by the City and TransAlta. The City's request for an order in this instance is similar to that made in Application 890007 wherein it requested a 50 percent share in the ownership of TransAlta's existing 500-kV transmission facilities in the Keephills - Ellerslie area. In the current instance, the request is made prior to the 240-kV double circuit transmission line having been constructed or, indeed, permitted to be constructed.

The Board's views respecting section 17 of the Act, as provided in the Memorandum of Decision, dated 1 May 1989, respecting Application 890007, apply in the current instance as well. As indicated in that Memorandum, the Board is not satisfied that it has authority to order the transfer of ownership of all or a part of a transmission line. In this instance, although the Board believes that section 17(2)(e) of the Act allows it to require efficient development of new facilities and ensure that a

party other than the owner has access to the use of the facilities, it is not satisfied that the words "share and participate, or otherwise combine its interest" are sufficient to allow the Board to direct the ownership of the transmission line, notwithstanding that the line has not yet been constructed.

The Board is therefore not prepared to proceed with a consideration of the request respecting ownership made by the City of Edmonton. The Board will be contacting the City further respecting its request that the Board not proceed to obtain Ministerial Approvals and issue the ERCB approvals.

DATED at Calgary, Alberta, on 12 July 1989.

ENERGY RESOURCES CONSERVATION BOARD

G J DeSorcy

G. J. DeSorcy, P.Eng.
Chairman

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

TRANSALTA UTILITIES CORPORATION
THE CITY OF EDMONTON (EDMONTON POWER)
240-kV TRANSMISSION LINE
ELLERSLIE - EAST EDMONTON AREA

Memorandum of Decision
(Interim Decision)
Application 880953

The Board has considered the evidence presented at the hearing held 8 September 1989, and has decided that it should proceed to request Ministerial Approvals and issue the permits and licences associated with the 240-kV line proposed by TransAlta Utilities Corporation, between Ellerslie and East Edmonton.

A further report providing detailed reasons for the decision will be forthcoming.

DATED at Calgary, Alberta, on 15 September 1989.

ENERGY RESOURCES CONSERVATION BOARD

G. J. DeSorcy, P.Eng.
Chairman

J. P. Prince, Ph.D.*
Board Member

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* J. P. Prince, Ph.D. was unavailable for signature but concurs with the contents and with the issuing of this decision.

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

TRANSALTA UTILITIES CORPORATION
THE CITY OF EDMONTON
240-kV TRANSMISSION LINE
ELLERSLIE-EAST EDMONTON AREA

Memorandum of Decision 2
Reasons for Decision
Application 880953

1 BACKGROUND

TransAlta Utilities Corporation (TransAlta), by Application 880953, requested Energy Resources Conservation Board approval to construct a double-circuit 240-kV transmission line in the Ellerslie-East Edmonton area. Following a public hearing of the application, the Board conditionally decided to approve construction of the line and issued Decision D 89-2.

In Decision D 89-2 the Board indicated that it would not proceed with a request for Ministerial Approvals, or with the issuance of ERCB approvals, until The City of Edmonton (The City) had an opportunity to make representations relating to the ownership of the line.

In a letter dated 31 May 1989, The City requested that the TransAlta approval be conditioned to allow The City 50 per cent ownership in the proposed line. In its Memorandum of Decision, dated 12 July 1989, the Board advised The City that it was not prepared to consider the ownership request because it was not satisfied it had the authority to do so.

Subsequently, by letter dated 5 September 1989, The City requested that the Board not proceed with the issuance of the approval, and that it be allowed the opportunity to prepare an application for a similar line which it would build and own.

The Board decided to hold a hearing to review the timing of the need for the 240-kV transmission line proposed in Application 880953 and, in particular, whether the timing of the need is such that it would allow the Board to consider an application to be filed by The City for approval to construct and operate a similar 240-kV transmission line. A public hearing was held in Edmonton on 8 September 1989 before Board members G. J. DeSorcy, P.Eng. (Chairman) and J. P. Prince, Ph.D. Those who participated at the hearing are shown on the attached table.

TransAlta advised the Board that it was appearing under protest because it intended to appeal the Board's decision to hold the hearing.

The Board issued an interim decision dated 15 September 1989, indicating that it was proceeding to obtain the necessary Ministerial Approvals for the TransAlta application. This report gives its reasons for that decision.

2 CONSIDERATION OF RELEVANT ISSUES

The Board considers the matters relevant to arriving at a decision are

- the period of delay if an application by The City was to be considered,
- the need for the line,
- the risk of not being able to supply the northeast (N.E.) area load in 1990,
- the cost of providing an adequate supply for the N.E. area load in 1990 without the line, and
- concerns of participants other than The City and TransAlta.

2.1 Period of Delay if an Application from The City Was Considered

At the hearing, The City indicated that it would be filing an application by 3 October 1989 to build the 240-kV transmission line on the route alignment granted in Decision D 89-2. On the basis of its response to questioning by Board staff, it would appear that The City's application might only address certain matters, such as the line terminations at Ellerslie 89S and East Edmonton 38S substations, in a preliminary manner. The City indicated it had not yet started negotiation of an agreement with TransAlta for the two terminations. Should such negotiations be unsuccessful, The City acknowledged that it may have to investigate other alternatives which could require additional transmission line right of way. The City also indicated that it had not contacted the landowners along the approved alignment to inform them of its intention to apply for approval to build the line along that route.

The Board is concerned about the degree of uncertainty associated with The City's proposed application. Given this uncertainty and the likelihood of a lengthy time period to process such an application, the Board believes that a delay of 6 months to 1 year to construct the transmission line would likely result.

2.2 Need for the Line

No one at the hearing disputed the need for the line. The Board continues to believe that the line is needed and notes that load data filed by TransAlta show the actual 1988 and 1989 loads to be higher than the forecasted loads prepared in 1987 and included in TransAlta's original application.

2.3 Risk of Not Being Able to Supply the Northeast Area Load in 1990

The City took the position that the N.E. area load would not be jeopardized because the Clover Bar units would be in operation and would unload the existing 240-kV lines.

Evidence filed by TransAlta indicated that over numerous periods in the summers of 1988 and 1989, the N.E. area load exceeded the firm capacity of the existing transmission system serving the area. TransAlta stated that no line overloading occurred, probably because when the transmission capacity in the area was exceeded, no 240-kV line single contingency outage occurred; or if an outage had occurred, Clover Bar units were running to supply the load.

TransAlta stated that in the summer of 1989, Clover Bar units were dispatched at significant levels because of power required for export and an unanticipated large number of outages among the coal-fired generating units. It submitted that export sales are unpredictable and unit failure is not something one plans for except to a degree indicated by experience (as a reasonable precaution).

The N.E. area load is forecasted to continue to increase. Therefore, it is apparent that the load would likely exceed the existing firm transmission capacity for a longer period of time in the summer of 1990. Hence the area load would be exposed to risk for a longer period than in previous years if the Clover Bar units were not operating.

The Board recognizes that Clover Bar can be expected to be dispatched in order to meet the generation requirements of the Alberta Interconnected System (AIS). This would effectively unload the 240-kV lines supplying the N.E. area and would alleviate the risk of overloading those lines. However, in view of the growth trend of the actual N.E. area load recorded in recent years, it can be expected that Clover Bar generation would have to be dispatched more often and at a higher capacity in order to keep loadings on the above-mentioned 240-kV lines below levels at which the system would be exposed to risk. Consequently, there would be some incremental cost associated with dispatching the gas-fired generating units longer than would normally be required to meet AIS requirements.

As well, since there have been occasions when the N.E. area summer load in 1988 and 1989 exceeded the transmission system firm capacity by more than 200 MW, the Board is concerned that The City's suggested operating strategy of unloading the 240-kV lines by utilizing the Clover Bar units might result in a very high proportion of the Clover Bar generation capacity being required throughout the crucial time periods.

The Board recognizes that switching substations in the city of Edmonton might be feasible as another backup. However, in spite of this potential flexibility, the overall risk in the N.E. area is higher for whatever period of time the applied-for transmission line is not available.

During the original hearing of Application 880953, TransAlta submitted that there are several scenarios that could lead to coincident outages of both circuits of a double-circuit transmission line. Some of the scenarios could lead to outages of the double-circuit 240-kV line 904L/908L in the N.E. area. The growth trend of the actual N.E. area load also indicates that, should a double-circuit outage to 904L/908L occur in the winter peak of 1990, the capacity of the Clover Bar plant might not be sufficient to supply all the load in the area.

In summary, the Board concludes that if the additional 240-kV line was delayed to allow consideration of an application by The City, the risk of not being able to supply the N.E. area load during 1990 would not be great. However, there would be some risk, as well as some increased costs to mitigate the risk.

2.4 Costs of Providing an Adequate Supply for the Northeast Area Load in 1990 Without the Line

The Board has reviewed the cost estimates for dispatching the Clover Bar units in the summer of 1990 to alleviate the risk of overloading the transmission system. The Board does not expect it to be as high as that suggested by TransAlta, but believes the cost would be at least $200 000 per month as estimated by The City.

2.5 Concerns of Participants Other Than The City and TransAlta

Participants at the hearing were concerned that the easterly RDA route contained in TransAlta's original application might be considered by The City as a possible route alternative in an application to the ERCB.

The City, however, stated that it would be applying only for a 240-kV transmission line on the route alignment approved by the Board in Decision D 89-2. The Board is therefore satisfied that these interveners' concerns have been answered.

3 CONCLUSIONS

The Board accepts the N.E. area historical load data and updated forecast as filed by TransAlta and continues to believe that TransAlta's proposed line is needed. The Board recognizes that dispatching the Clover Bar units could meet the load requirements in the summer of 1990, but at some incremental cost which would not be negligible.

Additionally, the Board is concerned that any delay in reinforcing the N.E. area transmission system would decrease the system reliability and increase the risk of disrupting as much as 20 per cent of the province's total electric load. For these reasons, combined with the considerable uncertainty respecting the length of delay in handling an application from The City, the Board has decided to proceed to request the necessary Ministerial Approvals related to TransAlta Application 880953. Upon receipt of same, it will issue the necessary permits and licences to TransAlta Utilities Corporation.

DATED at Calgary, Alberta, on 6 October 1989.

ENERGY RESOURCES CONSERVATION BOARD

G. J. DeSorcy

G. J. DeSorcy, P.Eng.
Chairman

J. P. Prince

J. P. Prince, Ph.D.
Board Member

TABLE PARTICIPANTS AT THE HEARING

Principals and Representatives (Abbreviations Used in Report)	Witnesses
The City of Edmonton (The City) P. A. Smith, Q.C.	A. Sadesky, P.Eng. A. Baird, P.Eng. F. Kardel, P.Eng.
TransAlta Utilities Corporation (TransAlta) J. G. Friesen	W. Nieboer, P.Eng.
Alberta Power Limited C. K. Sheard	
Industrial Power Consumers Association of Alberta D. E. Crowther	
Fountain Lake Community League B. Shields	
Lehndorff Land Developments J. Agrios, Q.C.	
Parents' Association, Colchester Elementary School P. Nissen	P. Nissen
County of Strathcona No. 20 L. A. Reynolds	R. J. Powell, P.Eng.
Sherwood Park Greenbelt Protection Association F. Gifford, P.Eng.	F. Gifford, P.Eng.
Sherwood Park Fish and Game Association A. Boyd	
Energy Resources Conservation Board staff M. J. Bruni T. F. Homeniuk, P.Eng. M. L. Asgar-Deen, P.Eng. T. Chan, P.Eng. B. Olliver	

The Hulbert Crescent Subdivision filed a written submission but did not appear at the hearing.

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

BONANZA OIL & GAS LTD., A UNIT OF POCO PETROLEUMS LTD.
APPLICATION FOR A WELL LICENCE — Decision D 89-3
ALTARIO FIELD — Application 890113

1 INTRODUCTION

1.1 Application and Intervention

Bonanza Oil & Gas Ltd., a unit of Poco Petroleums Ltd. (Bonanza), applied to the Energy Resources Conservation Board (ERCB or Board), pursuant to section 2.020 of the Oil and Gas Conservation Regulations, for a well licence to drill a well in legal subdivision 16 of section 9, township 34, range 1, west of the 4th meridian, to be known as BONANZA ALTARIO 16-9-34-1 (the proposed well). The purpose of the well would be to obtain production from the Belly River, Sparky, or Bakken zones.

An intervention opposing the application, primarily of concern for protection of native prairie, was filed by John Murphy and Wendy Murphy (the Murphys), occupants of the northeast quarter and south half of section 9 (NE 1/4 and S 1/2 of section 9) by right of a Crown grazing lease issued by the Special Areas Board under the Minister of Municipal Affairs. The Federation of Alberta Naturalists (FAN) also intervened on the issue of native prairie habitat protection.

The public hearing of the application was held in Altario, Alberta, on 28 February and 1 March 1989 before N. A. Strom, P.Eng., N. G. Berndtsson, P.Eng., and C. A. Langlo, P.Geol.

2 BACKGROUND

The proposed well would be located approximately 1 kilometre (km) south and approximately 6 km east of the hamlet of Altario. The area is characterized by rolling glacial topography where cultivated areas and native grasslands are interspersed over the land surface. Lower areas commonly contain sloughs, and small poplar bluffs are sparsely scattered across the landscape. The area has a semi-arid climate with typical annual rainfalls of 30 to 40 millimetres (mm) (13 to 14 inches) per year and occasional periods of drought. Primary industries in the area include cattle ranching, grain farming, and oil and gas production.

The proposed well would be located on native prairie, Crown land that is administered by the Special Areas Board of the Department of Municipal Affairs. The Special Areas Board was formed in 1938, at a time when

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations Used in Report)		Witnesses
Bonanza Oil & Gas Ltd., A Unit of Poco Petroleums Ltd. (Bonanza) R. C. Swist		L. S. Colebrook R. A. Brownless, P.Geol. I. Baker L. R. Lipsett, P.Eng. H. Spence W. T. Wilson, P.Eng. (of Bissett Resource Consultants Ltd.)
John and Wendy Murphy (the Murphys) J. W. Bodnar	Panel 1	D. Biggs
	Panel 2	G. Lakevold J. Sumner W. Hanson W. Fawcett R. Murphy C. Fawcett
	Panel 3	F. Murphy R. Buxton J. Westerlund C. Austin E. Mouly B. Mouly
	Panel 4	T. Crush
	Panel 5	J. Murphy W. Murphy K. Saggaser, P.Geol. C. Wallis, P.Biol. (of Cottonwood Consultants Ltd.)
Federation of Alberta Naturalists (FAN) Maryhellen Posey		Maryhellen Posey
Energy Resources Conservation Board staff C.J.C. Page C. S. Richardson J. R. Creasey, P.Biol. G. J. Dodd, P.Geol. I. E. Varga, P.Eng.		

successive annual droughts accompanied by serious soil erosion forced local farmers and some municipalities into insolvency. Approximately 2 million acres of land were turned over to the Minister of Municipal Affairs to be managed by the Special Areas Board. Under the Special Areas Act, the mandate of the Special Areas Board calls for the land to be rehabilitated and leased back to the agricultural community. Mineral surface leases for oil and gas development in the area are also issued by the Special Areas Board.

The Altario Field, as designated by the ERCB, is comprised of 31 sections of land on which oil and gas development commenced in 1955. In recent years oil and gas activity has increased, with the development of pools within the Cretaceous and Mississippian geological systems. To date approximately 40 wells have been drilled in the Field. The proposed well is adjacent to the southwest boundary of the Field, where the geological trend for development of the oil and gas reserves is oriented in a northeast/southwest direction (Figure 1).

For the proposed well (as shown in Figure 2), the gas well drilling spacing unit (DSU) is the normal one section size with the gas target area within the central part of the section having sides 300 metres (m) from the boundaries of the section. The oil well DSU as set out in Board Order No. SU 1088 (SU 1088) is one quarter section with the oil target area being the NE legal subdivision of the DSU.

In part of the adjoining Altario Field, Board Order No. SU 1533 provides for reduced oil well DSUs of one legal subdivision with the oil target area being the NW quadrant of the DSU. Also in the Altario Field, a Geological and Topographical Order (GTO Order), Board Order No. GTO 8891, covers the west half of section 14-34-1 W4M and provides for greater oil target flexibility by suspending the one Lsd target areas and placing restrictions of a 200-m buffer zone on the east and south sides of the half section, an interwell distance of 200 m, and only one well per Lsd within the half section (Figure 1).

3 ISSUES

The Board considers the issues with respect to the application to be

- o the rights of the mineral and surface lessees,
- o the need for protection of native prairie habitat,
- o subsurface geology and well target areas,
- o vertical and directional drilling economics,
- o future development options,
- o the impact of the well and production facilities on the Murphys and on the land surface.

4 THE RIGHTS OF THE MINERAL AND SURFACE LESSEES

4.1 Views of the Applicant

Bonanza argued that the broad issues of public interest in the preservation of natural habitats raised by the Murphys were beyond their legal and proprietary interest in the land as grazing lessees. It stated that the interveners' concerns relating to preservation of native prairie and wildlife had been improperly placed before the ERCB. Bonanza contended that the interveners were not entitled to deal with those issues or interests without obtaining the support and authority of the Special Areas Board and noted that the Special Areas Board was not opposing the application. Bonanza stated that its right of access to the proposed site and issues of reclamation should be determined by the Special Areas Board and the Land Surface Conservation and Reclamation Council (LCRC) respectively, and not by the ERCB.

4.2 Views of the Murphys

Mr. Murphy considers himself custodian of the NE 1/4 of section 9 pursuant to the grazing lease which he holds from the Special Areas Board. Witnesses appearing on behalf of the Murphys suggested that lessees of Special Areas lands are very similar to deeded owners in that they are charged with care and maintenance of the land and are subject to penalties for misuse of native prairie. The Murphys submitted that the rights of the mineral owner are not exclusive of the rights of the surface owner and that Bonanza must adhere to the requirements of the Alberta legislation and regulations. The intervener referred to the function of the ERCB as ensuring the conservation of the environment as well as the energy resources in the Province of Alberta.

4.3 Views of the Board

The Board notes that under the terms of its Crown mineral lease, Bonanza has the right to drill for, and recover, any petroleum and natural gas that may occur under section 9. Pursuant to his grazing lease from the Special Areas Board, Mr. Murphy has an interest in the land as a grazing lessee and therefore any impacts on those rights must also be considered. The rights in either case are subject to the provisions of the Mines and Minerals Act, the Special Areas Act, and any other Acts of the Legislature of Alberta that prescribe, apply to, or affect the rights and obligations of the mineral or grazing lessees.

Pursuant to section 2 of the Energy Resources Conservation Act, the Board is empowered to ensure environment conservation in the development of energy resources. The Board is therefore satisfied that it is proper to look at the issue of impact on native prairie habitat in considering the application for the proposed well.

The Board is further satisfied that in considering the potential impacts of a well on Special Areas lands, the ERCB may have regard for the methods proposed for construction, reclamation, and restoration of a well site and its access road. If it deems appropriate, the Board is also satisfied that it may condition a well licence to mitigate any such impacts. The Board recognizes that the Special Areas Board and the LCRC also exercise authority in ensuring protection of the land surface, but believes that none of the above have exclusive jurisdiction.

5 THE NEED FOR PROTECTION OF NATIVE PRAIRIE HABITAT

5.1 Views of the Applicant

The applicant did not present or question evidence presented with respect to the general issue of need for protection of native prairie habitat. However, in discussing the impact of the proposed well, it stated that it would comply with all guidelines and regulations imposed by the Special Areas Board, the LCRC, and the ERCB. The applicant also stated that it would consult with the appropriate authorities respecting reclamation practices and grass seed mixes to be used to revegetate disturbed areas. It further expressed concern that this single proposed well site should not be used as the example to formulate policy for all native prairie impacted by the oil and gas industry.

5.2 Views of the Interveners

The Murphys and the witnesses who appeared on their behalf expressed the view that preservation of native prairie habitat is imperative and expressed concern that the applicant failed to recognize or address the environmental implications of the proposed well. They submitted that native prairie grassland is part of a rapidly diminishing ecosystem and that the impact of resource development on native prairie can be significant. The Murphys submitted that their views respecting the preservation of native grasslands were shared by several conservation groups, government agencies, members of the oil industry, and the general public. They identified the Prairie Conservation Action Plan (PCAP) as an initiative endorsed by the provincial government which identifies conservation strategies for the prairie region.

Witnesses for the intervener identified specific problems associated with oil and gas development such as the impact of herbicides and sterilants, deficiencies in the existing guidelines for reclamation including the use of non-native plant species, and irreversible damages caused by clearing and soil stripping practices. Concerns about impacts on the natural habitats including altered grazing patterns, introduction of plant species that are inferior for grazing compared to native species, and the potential for destruction of endangered species of plants and animals were also identified.

The Murphys suggested that although the Special Areas Act had been a mainstay in the preservation of native grassland in the past, there is also a need to devise suitable policies to control and prevent cumulative impacts. While the Murphys' panels generally expressed the view that carefully controlled access for oil and gas development should be allowed, they considered current reclamation standards, especially stripping of topsoils, to be very damaging to valuable native grasslands. Also they believed that oil and gas developments should be disallowed in certain critical native prairie areas.

FAN submitted that it is crucial that thorough reclamation be undertaken and that the land be protected as much as possible where disturbance is unavoidable. It stated that proper reclamation means restoring the land as close as possible to the state that existed prior to disturbance. It was concerned that reclamation as interpreted by the applicant was limited to protection of land from erosion and restoration to functional forage land. FAN emphasized that the introduction of excessively aggressive non-native plant species should be avoided altogether. FAN recommended that the ERCB establish a consultative process involving government agencies and other interested parties to design suitable reclamation programs for native prairie grassland.

Mr. Cliff Wallis of Cottonwood Consultants Ltd., appearing on behalf of the Murphys, described the area of the proposed well site as a grassland community bordering the Northern Fescue Grassland and Central Aspen Parkland biogeographic areas. Mr. Wallis expressed the view that the lack of a detailed environmental impact assessment by the applicant underlines an apparent lack of understanding of the complexities and values of native grassland ecosystems. He submitted that although detailed field investigations had not been carried out, the site in question should be quite representative of the biogeographic regions cited above and in addition to providing habitat for common species, would likely also be used by rare or uncommon wildlife species. He submitted that because less than 5 per cent of native prairie areas remains in an unaltered state because of extensive land cultivation prompted in part by government agricultural incentives, the remaining areas should be viewed as extremely valuable heritage resources.

Mr. Wallis stated that the PCAP identifies a target of 10 per cent of each biogeographic region to be under some form of protection, and submitted that since less than that amount is left in Alberta, as much as possible of what remains should be protected. He expressed the view that environmentally significant areas include both unique habitats with limited representation or small remnants of once larger habitats. Mr. Wallis identified habitat fragmentation as the most serious threat to biological diversity and the primary cause of the present biological extinction crisis. He submitted that the area surrounding the proposed well site may be part of an environmentally significant ecosystem and observed that very few landowners exhibit the dedication of the Murphys

in endeavouring to protect the native prairie. Mr. Wallis contended that since oil and gas developments create significant impacts which cannot be fully mitigated, strong consideration should be given to shifting such developments onto cultivated lands wherever feasible.

Mr. Wallis submitted that because of limited research and little demonstrated success in restoration of native grasses, even apparently small impacts from oil and gas development can be damaging. He also reiterated a key point made by other panels, that surface impacts should be reduced by minimal topsoil disturbance and careful selection of access road routes to avoid the most significant areas of a site.

5.3 Views of the Board

The Board recognizes that the issue of preservation of native prairie is an important public concern, as indicated by the testimony of a majority of local panel members who ranch or farm in the general Altario area and also as reflected in the content of the publication entitled Prairie Conservation Action Plan. This plan, drafted with participation by several private parties, government agencies in the Canadian prairie provinces, and Environment Canada, provides a statement of goals for the ultimate conservation of native grassland areas.

The Board notes that the PCAP does not suggest prohibiting development on native prairie but provides recommendations to effectively manage the remaining native prairie areas and to minimize the impacts of land use activities. The Board also agrees with the position put forward by several members of the Murphys' panels that discipline, good management, and flexible guidelines can be utilized to reduce the impact of oil and gas development activity on native prairie.

The Board recognizes that ranchers, farmers, and other occupants of the Special Areas lands want the government to establish a policy to protect native prairie and to have an integrated process among government agencies that would ensure that the policy and guidelines under it are enforced. The Board believes that such a policy and guidelines would ensure fair and consistent treatment of all land users, and therefore would be beneficial in facilitating economic, efficient, and orderly oil and gas development in native grasslands areas. In view of the problems expressed by the intervener panels and the need for fair and consistent direction to the oil and gas industry, the ERCB would be prepared to assist in a forum where all stakeholders including landowners and occupants (ranching, farming, oil and gas, and others) in the general Special Areas region would be invited to present proposals to deal with the concern. The ERCB believes that in the Special Areas the Special Areas Board would be able to play a lead role in such a forum. The ERCB also believes that the PCAP could be employed as a basic reference for the development of the desired policy.

6 SUBSURFACE GEOLOGY AND WELL TARGET AREAS

6.1 Views of Bonanza

Bonanza submitted that the proposed well would be drilled to evaluate the hydrocarbon potential demonstrated by productive wells in adjacent sections. If successful, the well would produce from Belly River, Sparky, and/or Bakken reservoirs.

Bonanza implied that with the ability to readily market the oil and recover development costs, the Bakken would be the primary objective with an estimated chance of success of 30 per cent. Bonanza interpreted the Bakken sand as an elongate marine bar with potential for either oil or gas production with oil being the most likely. It submitted that Bakken production was most likely to occur on Paleozoic highs which it interpreted from geophysical isochron and geological structure maps. Any shift away from the structural highs would reduce the possibility of success. If the proposed well were successful, the areal extent of the Bakken pool would likely cover most of the northeast quarter of section 9 with the potential for additional subsurface locations in Lsds 9, 10, and 15.

Bonanza interpreted the Sparky sand to be a northeast-southwest trending deltaic sequence with potential for gas production from a local structural trap created by the Paleozoic high interpreted in the NE 1/4 of section 9. Bonanza interpreted its proposed location as the highest point of this structural trap and considered its chances of a Sparky success to be 75 per cent.

Bonanza stated that its choice of well location placed the proposed well on target for both gas and oil, as illustrated in Figure 2. It acknowledged that a successful Bakken oil well, while being on target for SU 1088 quarter section spacing oil wells, would be off-pattern for probable future one Lsd oil well spacing with northwest quadrant targets. If oil production were established Bonanza indicated it might consider obtaining a GTO Order for the quarter section to provide additional target area flexibility so as to reduce land impacts. In response to questioning, Bonanza indicated that to drill a well directionally from cultivated lands on the adjoining section 10 would involve a horizontal displacement of 400 m to stay within both the common oil and gas target areas in section 9.

6.2 Views of the Murphys

The Murphys questioned Bonanza's geological interpretation and submitted that seismic information alone does not confirm the presence of hydrocarbons. The intervener suggested that the Sparky sand may be relatively thin and perhaps of poor reservoir quality, which raised

doubts about the economic viability of the Sparky as a gas-bearing zone. Therefore, they regarded the Bakken oil as the only objective of economic interest.

The intervener observed that because the applied-for location was inferred from Bonanza's seismic data, a bottom-hole location closer to the seismic data points would reduce the risk of drilling a dry hole. The Murphys proposed that a well at a surface location in legal subdivision 13 of the adjoining section 10 could be drilled directionally to an alternative bottom-hole location within the existing SU 1088 northeast oil target area of the NE 1/4 of section 9, with a small horizontal displacement.

6.3 Views of the Board

The Board recognizes that Bonanza's first priority in drilling the proposed well would be to examine the possibility of economic success for either oil or gas production. Consistent with that priority would be a desire to drill in the common oil and gas target window so that production from the well would not be subject to curtailment by off-target penalty restrictions.

The Board notes that although the prospective zones are associated with established Paleozoic structure trends, there is no specific information, such as hydrocarbon/water interfaces, to indicate the down-dip limit of potential hydrocarbon occurrences within these zones. This, plus the fact that there is no seismic data to verify the inferred high as submitted by Bonanza, leads the Board to conclude that both Bakken oil and Sparky gas pools may cover a rather large part of the NE 1/4 of section 9.

Considering the possibility for future Bakken oil production on one Lsd spacing, the optimum initial location would appear to be in the NW quadrant of Lsd 9 rather than the SW quadrant of Lsd 16 because the latter would place the initial well less than 100 m away from the target location for the offsetting Bakken oil well in Lsd 9 if the Bakken oil prospect materializes. The foregoing notwithstanding, the Board agrees with Bonanza that drilling a directional well from section 10 to either of the above bottom-hole locations would involve a lateral displacement of some 400 m.

7 ECONOMICS OF OIL AND GAS RECOVERY BY VERTICAL AND DIRECTIONAL WELLS

7.1 Views of the Applicant

Bonanza submitted that the cost of a completed vertical well including necessary surface and production equipment would be $303 000 (Table 1). Based on this initial capital investment, plus estimated operating costs and an estimated oil recovery of 22 300 cubic metres (m^3) (140 000

barrels) within the next 15 years, the development of Bakken oil would be economic. It also stated that the develoment of the Sparky gas with a vertical well would be equally economic.

Bonanza also assessed the economics of developing Bakken oil by drilling a directional well to its proposed bottom-hole location, from a surface location in Lsd 13 of section 10, representing about 400 m of horizontal displacement. The completion cost for this well, including larger pumping equipment and an allowance for future replacement of downhole equipment, was estimated at $591 000. Using this initial capital investment, plus the same operating costs, oil production rates, and recovery as noted for the vertical well, Bonanza calculated that the development of the Bakken oil with its first well as a deviated well would not be economic.

7.2 View of the Murphys

The Murphys submitted that in order to preserve the native prairie on the NE 1/4 of section 9, Bonanza should drill its well directionally from a surface location on cultivated land either in the NW 1/4 of section 9 or the NW 1/4 of section 10. They believed that the additional cost of drilling a directional well could be offset in part by eliminating the cost of an access road and reducing lease construction and restoration costs. As noted earlier in Section 6.2 of this report, the intervener suggested that Bonanza consider directionally drilling a Bakken oil well from section 10 with a smaller horizontal displacement, but they did not provide an economic assessment. Alternatively, they suggested that Bonanza should postpone its plans until oil prices recover to the point at which a directional well would be economic.

7.3 Views of the Board

The Board agrees with Bonanza that the cost of a deviated well would be considerably greater than a vertical well, the degree of variance being partly proportional to the amount of deviation. Bonanza's evidence indicated that a Bakken well deviated 400 m would be nearly twice the cost of a vertical well. Although the Board believes that Bonanza has made an excessive allowance for well production equipment, it agrees that a deviated well of 400 m would be at least 50 per cent more expensive than a vertical well. On that basis, a deviated well with 400-m displacement would be barely economic.

The Board notes, however, that the economics of subsequent deviated wells from a single pad location could be significantly improved.

8 FUTURE DEVELOPMENT OPTIONS

8.1 Views of Bonanza

Bonanza submitted that if the proposed vertical well were successful for both Sparky gas and Bakken oil, dual completion of a lower zone pumping oil well and an upper zone flowing gas well would pose significant operational problems. Therefore, it would likely produce the Bakken first and within the economic life of the Bakken, it would expect to find the technology to allow simultaneous production of the two zones. Bonanza stated that a dual completion would be much more difficult, if not impossible, in a 400-m deviated well.

Provided the proposed well was a significant Bakken oil success (ie, sustained relatively high production rates), Bonanza stated at the hearing that it would pursue directionally drilling future development wells from the site of the proposed well. The bottom-hole locations of those wells would be based on geological interpretation of data from the initial well and the target area flexibilities provided by a GTO Order with one Lsd DSUs.

8.2 Views of the Murphys

Although the Murphys did not directly address the issue of future development, concerns were generally expressed regarding the impact of further development on the prairie habitat in the immediate area.

8.3 Views of the Board

The Board agrees with Bonanza that dual zone completion for simultaneous production from the Bakken and Sparky zones would not likely be feasible. On that basis, the Board believes that either Sparky gas production would have to be deferred, or that an additional well would have to be drilled to accommodate production from a second zone.

While the Board agrees that in most cases the first well in a pool is drilled vertically, the anticipation of additional directional wells should be a priority in determining the first surface location. This approach would be especially important in the specific circumstances under consideration in the NE 1/4 of section 9. In addition, identifying a location which would provide for minimum lateral displacements for future directional wells would reduce future capital and operating costs for such wells.

On that basis, the Board would view any location granted for the drilling of additional wells as a potential pad location for drilling of other wells in the 1/4 section. The Board also notes that Bonanza inferred, in response to questioning, that no other surface sites in the NE 1/4 of section 9 would be required.

9 IMPACT OF THE WELL AND PRODUCTION FACILITIES ON THE MURPHYS AND ON THE LAND SURFACE

9.1 Views of the Applicant

Bonanza submitted that it is entitled to an order permitting it to exercise its legal rights by way of the granting of a well licence, and any conditions attached to the well licence should be the same as those that are widely held by the industry in this particular area.

Bonanza acknowledged that its proposed well would have certain impacts on the land as do other industrial and agricultural activities. It emphasized that it would conduct its drilling and production activities so as to minimize the impacts on the land and on the Murphys' use of the land, that being the grazing activity. It further emphasized that it would conduct its activities in accordance with requirements of the Special Areas Board, the LCRC, and the ERCB.

Bonanza filed a lease construction sketch, Figure 3, showing how it would propose to minimize land disturbance. Also it undertook to minimize surface disturbance by performing the following:

- not using soil sterilants,
- constructing its access road and lease in accordance with its revised survey plan which would cause less earth to be moved for levelling,
- not grading the road until the well is confirmed productive,
- drilling the well during the winter or the dry season,
- stockpiling topsoil on the high side of the lease to avoid contamination,
- if the well is productive, downsizing the lease and recontouring the lease areas not required for production operations,
- restoring topsoil, and reseeding the area in consultation with the Special Areas Board and the LCRC,
- constructing a five-wire fence to enclose the access route and well site,
- installing double steel gates at the lease access point and at the corners adjacent to the line fence,
- locking the gates and providing a key to the Murphys.

In response to questioning, Bonanza stated that utilizing a remote sump for drilling waste had not been considered and in its opinion was not justified. Bonanza did acknowledge, however, that using a remote sump would result in less disturbance to the lease area. Bonanza stated that a non-toxic drilling fluid would be used for this well.

When questioned as to the facilities required on the lease during the production phase, Bonanza stated that several vessels would be required, even if the well was a gas producer. Additionally, Bonanza would be prepared to install "stock crossing" and "children playing" signs at the boundary points of the SE 1/4 of section 17 with the main east-west road going past the Murphy farmstead.

Bonanza stated that if given the opportunity it would work to improve reclamation standards in this particular area in accordance with what is practical from the point of view of the Special Areas Board and the LCRC. Bonanza did not comment on the intervener's request for an environmental impact statement, nor the preparation of a restoration plan. It stated that the requirements of the LCRC, the Special Areas Board, and the ERCB would be implemented in Bonanza's activity.

Bonanza presented a survey which concluded that a low potential exists for historical or archeological resources in the general lease area. Bonanza stated that it was awaiting a reply from Alberta Culture regarding the archeological inventory, and would advise Alberta Culture of the recent changes in the access route and well location.

9.2 Views of the Murphys

The Murphys expressed the view that oil development is destroying the unique way of life which they have chosen and the privacy which they are now able to enjoy. That way of life includes voluntary restrictions on the land in question, including prohibition of vehicular traffic on the land surface of the NE 1/4 of section 9. The effects of noise and the potential for dangers due to increased vehicular traffic and construction activity, contamination of air, soil, or ground water, and reduction in quality of drinking water were identified as specific concerns.

In addition to lifestyle impacts, the Murphys expressed concerns respecting the physical disturbance to the land surface and the resulting reduction in agricultural productivity. They cited impacts in the area of a well site related to the inconvenience and extra management required to handle cattle, potential future weed control problems, and spreading of non-native plant species.

With respect to reclamation, the Murphys questioned the current practices utilized by the industry and those proposed by Bonanza. Although the strong preference of the Murphys was for the denial of the well licence application, they did propose mitigative measures in addition to those agreed to by Bonanza which should be undertaken if the well were approved.

The Murphys believed that these measures would reduce the impacts from the well on their lifestyle and on the land surface. Those measures included:

- completion of an environmental impact assessment by the applicant prior to issuance of a well licence,
- completion of a restoration plan prepared by a qualified research scientist and an environmental consultant, prior to issuance of a well licence,
- that Bonanza pay all costs of restoration,
- that Bonanza post a bond to cover restoration costs and be required to retain its lease until restoration is attained,
- that a 2- to 3-m undisturbed belt be left around the inside perimeter of the well site and access road to allow native species to re-establish,
- that well product be pipelined to a collection facility at the road allowance,
- no sump on the well-site,
- minimizing the area required to be levelled and the removal of topsoil,
- restoring the current densities of plants on the reclaimed site,
- restricting the introduction of non-native plant species to the site,
- utilizing native seed for restoration,
- ensuring that domestic water quality does not deteriorate,
- ensuring that all Bonanza personnel operate their vehicles in a safe and prudent manner,
- not installing any surface structures for gas production if the well is established as a gas producer,
- drilling at a time of year when no cattle are on the land, ie, in winter (cattle grazing most prevalent in June and July),
- minimizing road development by driving across the prairie without having a road bed built,
- performing a historical resource assessment to establish the archeological potential of the area.

9.3 Views of the Board

The Board believes that the Murphys' adopted lifestyle and land use practices should be preserved in degree, bearing in mind the advice of several panel members as outlined in Section 5.2 of this report and also having appropriate regard for overall public interest. If a well licence is granted the Board concludes that it would not be economically viable for the applicant to directionally drill the proposed well from a surface location outside of the NE 1/4 of section 9. In that instance some degree of impact on the land and the Murphys' current use of it would surely occur.

The Board concludes that impacts on the NE 1/4 of section 9 can be minimized by drilling the well during frozen ground conditions. Under those conditions, there would be no need for construction of an access road, and stripping of topsoil on the drilling site would be confined to the minimum level needed to prepare a drilling site. Also, as the Murphys indicated that cattle graze the NE 1/4 of section 9 in June or July, a winter drilling schedule would not conflict with this part of their ranch operation.

Additionally, the use of a remote sump would further minimize the area of drillsite construction. All these measures would be a practical means of minimizing grassland disturbance in connection with the drilling of the proposed well.

The Board believes that the revised construction plan submitted by Bonanza goes a considerable way in the direction of minimizing land disturbance in accordance with the wishes expressed by the Murphys. However, the Board notes that the Murphys have listed several conditions that focus on restoration of disturbed lands using native plant species in preference to non-native plants. Bearing in mind prompting from several members of the intervener panels to protect native grasslands, to the extent practical, the Board believes that further refinement of the Bonanza construction plan would be in order. The Board also believes that standard reclamation guidelines do not clearly address the issue of protecting native grasslands. Under these circumstances, if a licence is granted, the Board believes that the proposal by the Murphys to have a specialist knowledgeable in both native grassland ecology and protection and restoration of native grassland species available to provide advice concerning construction activities would be particularly advantageous. The Board would expect Bonanza, with mutual agreement from the Murphys, to retain such a specialist consultant. By scheduling drilling for the winter, it would also be feasible for the same consultant to make an abbreviated environmental survey of the general site to ascertain if there are any extraordinary reasons why further changes to the Bonanza site construction program would be warranted.

The Board would not be prepared at this time to approve an oil battery on the well site as outlined in the Bonanza construction plan. Until it

is known how many wells and what volumes of oil and gas would likely be produced to the battery, the most suitable construction and restoration program could not be properly evaluated. In the event that oil production is established, a separate application would therefore be required for approval of a permanent battery. At this time the Board can state that as part of the application the Board would require that Bonanza evaluate the feasibility of placing such facilities on adjacent cultivated lands with the required flow line laid adjacent to the well-site access road. Such a facility should consider the future use of the oil battery for additional oil wells in the NE 1/4 of section 9 and gas handling facilities if gas production is also established.

The Board, as a special measure in this instance, would be prepared to consider and approve skid-mounted temporary production testing facilities at the subject well site.

10 FINDINGS AND CONCLUSIONS

The Board concludes, based on the evidence presented, that prospects for both Sparky gas and Bakken oil exist in the NE 1/4 of section 9. As well, up to four Bakken oil wells on one Lsd spacing might be needed. At the same time the Board recognizes that the Murphys have endeavoured to maintain maximum protection of native prairie on this quarter section by excluding mechanized access and controlling grazing and believes that such protection should continue to the optimum feasible degree.

Considering all factors, the Board believes that the fairest treatment would be to grant the proposed well-site location on the understanding it could serve as a pad for drilling the initial and follow-up wells, but that stringent conditions should be imposed regarding the season for drilling access, site construction, soil stripping, land access and restoration, and placement of drilling and production facilities.

Evidence presented at the hearing strongly suggests that native grassland which is heavily damaged or removed in connection with oil and gas developments, or other land disturbance activities such as cultivation for agriculture, is extremely difficult to restore. The evidence was that regeneration of native grassland by invasion or seeding has not yet been demonstrated to be successful.

In the circumstances, a specialist knowledgable in native grassland ecology and its protection and restoration should be retained to provide advice concerning the construction program for the well site and access road and measures that could be used to enhance the possibilities of restoration.

The issue of preservation of native prairie grasslands, including preserving the full range of species of native flora and fauna, and habitat critical to them, is an issue of general public importance. The ERCB senses that there is relatively wide support from rural areas where there are still large tracts of native prairie, for the government to establish a viable policy aimed at preservation of native prairie and a process that ensures that the policy would be enforced. The Board believes that developing such a policy, including aspects of policy that provide for fair and consistent rules for allowing or disallowing oil and gas development, would be consistent with the basic objectives of the Energy Resources Conservation Act and the Oil and Gas Conservation Act. Such a policy would draw a suitable balance between access to oil and gas resources and conservation of the environment, and thereby promote economic, orderly, and efficient development of the Province's oil and gas resources.

The Board understands that the PCAP identifies a set of goals aimed at preserving remaining native prairie grasslands targeted for implementation by 1991. The PCAP also has drawn support from the provincial government and several conservation groups. The ERCB believes the Special Areas Board (Department of Municipal Affairs) working with Forestry, Lands and Wildlife would be able to play a lead co-ordinating role in the development of guidelines and procedures that would ensure manifestation of the Prairie Conservation Action Plan within the Special Areas. The ERCB would be willing to participate in any such forum and would expect that the energy industry associations would want to take an active role. The ERCB intends to communicate with the Special Areas Board further regarding this issue.

11 DECISION

The Board is satisfied that the proposed well should proceed and approves the well licence application in accordance with the findings outlined in this report. The well licence will be issued subject to the following conditions:

(1) Unless otherwise agreed to by the Murphys and Bonanza, drilling operations shall be restricted to winter months when access to the site is only on ground frozen sufficiently to preclude compaction from heavy vehicles. Stripping of soils should be avoided to the extent practical.

(2) All drilling fluids shall be contained in surface steel tanks and be removed to a remote sump approved by the Board.

(3) Bonanza shall retain a specialist in native grasslands ecology, including its protection and restoration, to overview and advise on refinements to the Bonanza construction and restoration plans. The specialist would be

expected to conduct an abbreviated environmental survey during the 1989 summer and autumn seasons to ascertain if there are any extraordinary reasons why further significant changes to the Bonanza well site and access road construction program would be warranted.

(4) There shall be no placement of temporary surface production facilities on site without prior approval from the ERCB.

The Board will communicate further with the Special Areas Board and Forestry, Lands and Wildlife regarding drafting of guidelines and procedures for the use, protection, and restoration of native prairie grasslands within the Special Areas.

DATED at Calgary, Alberta, on 14 July 1989.

ENERGY RESOURCES CONSERVATION BOARD

N. A. Strom, P.Eng.
Vice Chairman

C. A. Langlo, P.Geol.
Acting Board Member

N. G. Berndtsson, P.Eng.
Acting Board Member

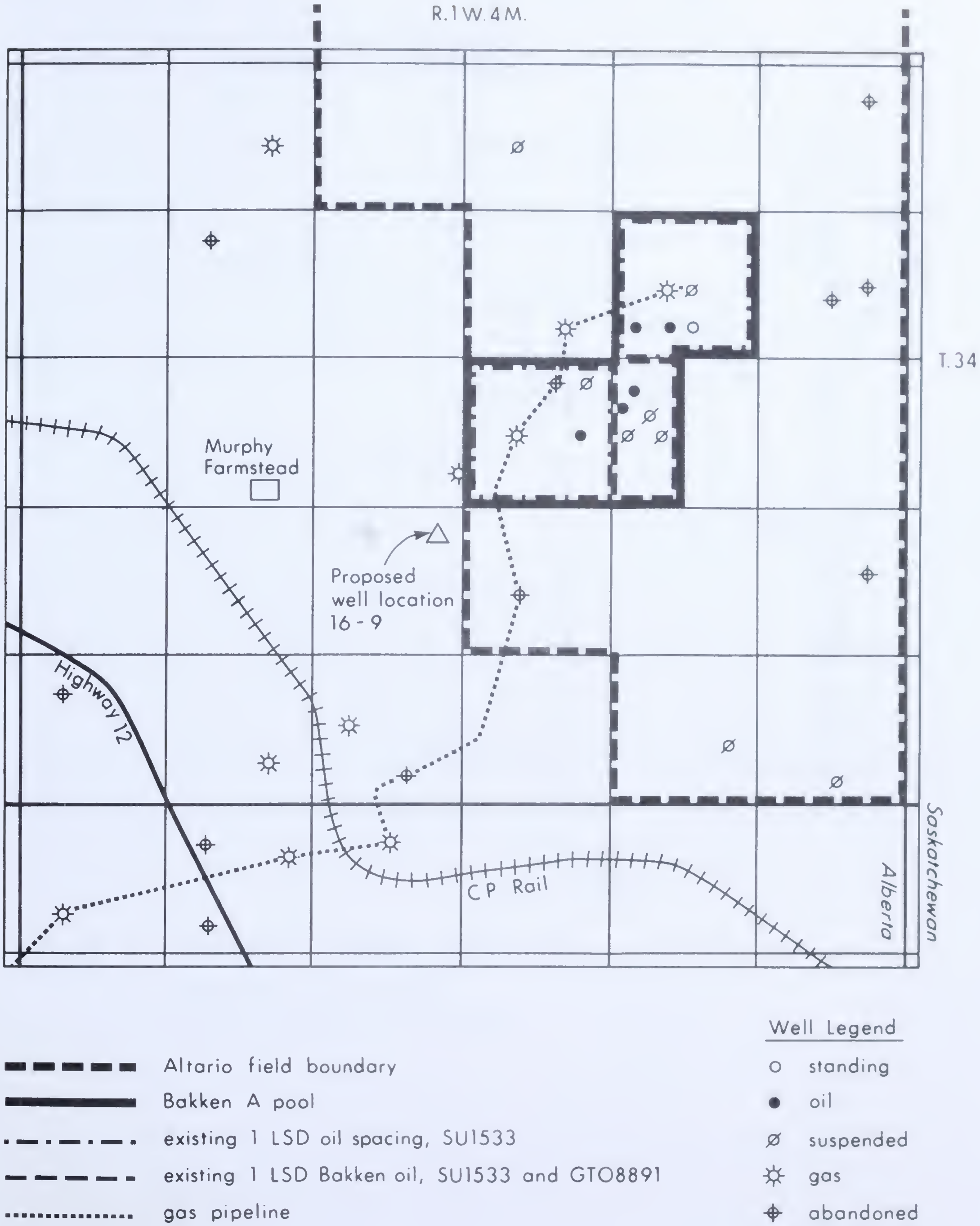

FIGURE 1 OIL AND GAS DEVELOPMENT IN ALTARIO FIELD
Application No. 890113
Bonanza Altario 16-9-34-1

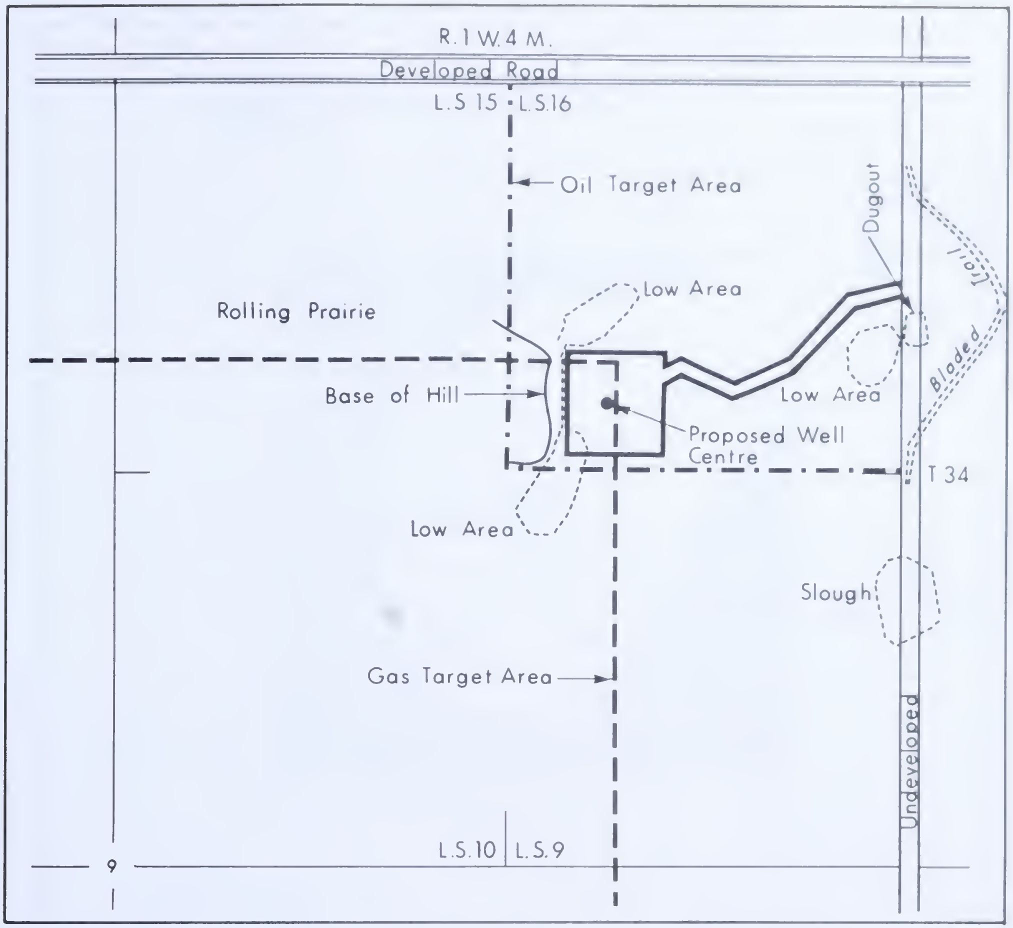

FIGURE 2 PROPOSED SURFACE LOCATION
Application No. 890113
Bonanza Altario 16-9-34-1

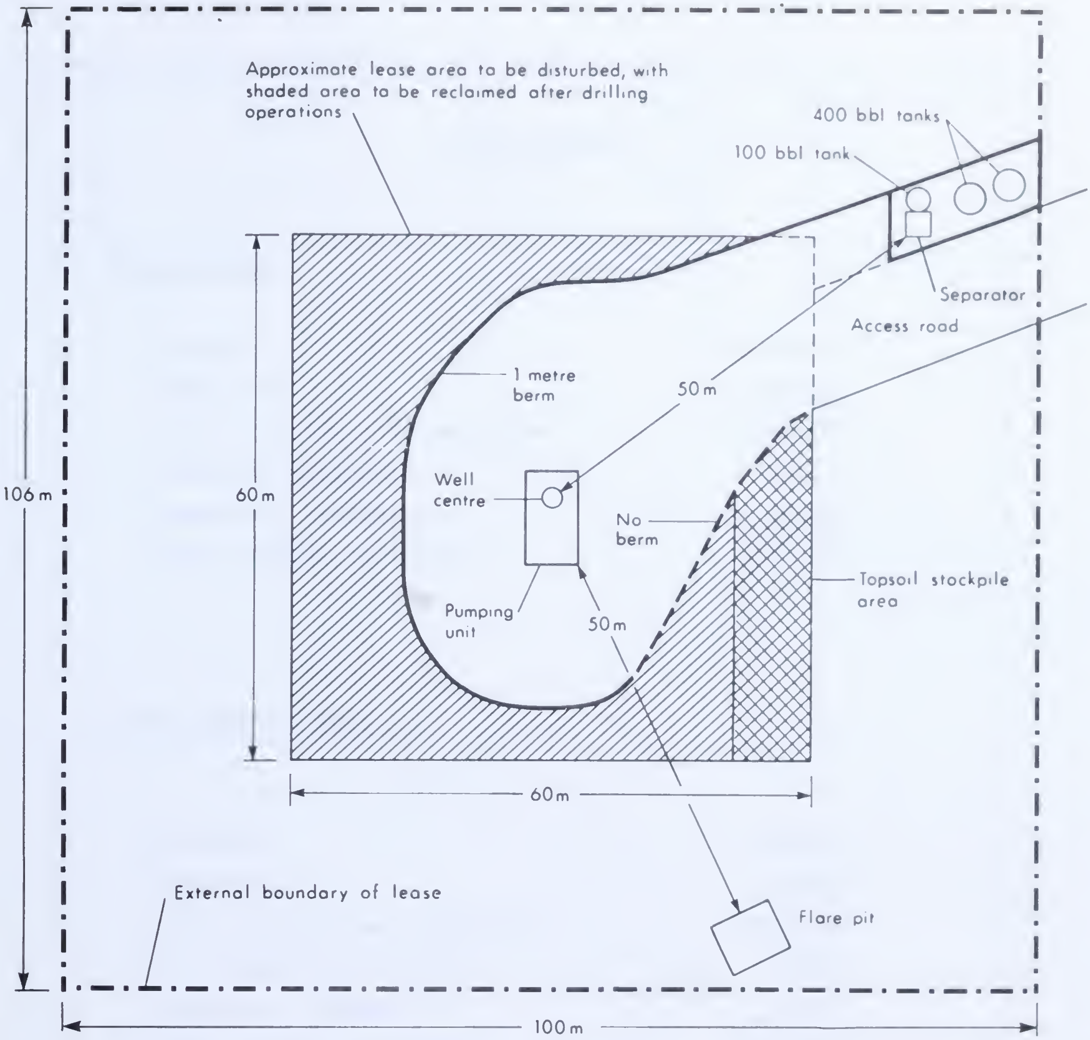

FIGURE 3 PROPOSED LEASE PLAN FOR BAKKEN OIL WELL
Application No. 890113
Bonanza Altario 16-9-34-1

COST ESTIMATES

Vertical well

Dry hole	$165,500
Completion	74,500
Total drilling and completion	$240,000
Producing equipment	46,000
Separator, tankage etc.	17,000
Total capital investment	$303,000

400 m deviated well

Dry hole	$226,000
Completion	76,000
Total drilling and completion	$302,000
Well producing equipment	272,000
Separator, tankage etc.	17,000
Total capital investment	$591,000

TABLE 1 Bonanza's Cost Estimates for Vertical and Directional Wells.
Bonanza Altario 16-9-34-1
Application No. 890113

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

APPLICATIONS BY PHILLIPS PETROLEUM RESOURCES, LTD.
FOR PERMITS TO CONSTRUCT PIPELINES
TO TRANSPORT SOUR GAS AND FUEL GAS
IN THE SALTER FIELD

Decision D 89-4
Applications 882129 and 882130

1 INTRODUCTION

1.1 Applications

Pursuant to Part 4 of the Pipeline Act, Phillips Petroleum Resources, Ltd. (Phillips) submitted an application for a permit to construct approximately 33 kilometres (km) of 114.3-millimetre (mm) and 168.3-mm outside diameter (OD) pipeline. The pipeline and related facilities would transport sour gas, with a maximum hydrogen sulphide (H_2S) content of 154.5 moles per kilomole, from wells located in legal subdivision (Lsd) 15, section 24, township 26, range 8, west of the 5th meridian, Lsd 6-25-26-8 W5M, Lsd 4-36-26-8 W5M, and Lsd 4-1-27-8 W5M to the existing Petro-Canada Wildcat Hills Gas Plant (the gas plant) located at Lsd 6-16-26-5 W5M.

Phillips also submitted an application for a permit to construct approximately 33 km of 60.3-mm OD pipeline and related facilities to transport sweet fuel gas from the gas plant to operate the emergency shut-down valves located on the sour gas line, to provide fuel gas for the line heaters, and to provide instrument gas at the well sites. Phillips proposed to place the fuel gas pipeline in the same ditch as the sour gas pipeline.

The applied-for route of the pipelines is shown in the attached Figure 1.

1.2 Hearing

The applications were considered at a public hearing in Calgary, Alberta, with Board Members F. J. Mink, P.Eng., E. J. Morin, P.Eng., and Acting Board Member R. G. Evans, P.Eng., sitting. The hearing was opened on 14 February 1989 but was adjourned to 1 March 1989, at the interveners' request. The hearing continued on 2, 3, 10, and 16 March 1989 with a site visit on 7 March 1989 to view the land features in the vicinity of the applied-for preferred pipeline route.

Participants at the hearing are listed in Appendix A.

1.3 Background Information

The subject applications involve the tie-ins of four sour gas wells in the Salter Field and the installation of a sour gas and a fuel gas pipeline to connect the wells to the existing gas plant located at Lsd 6-16-26-5 W5M.

The wells were developed in the early 1980s. In April 1981, a gas plant application was submitted by the applicant and approved by the Board, with the approved plant location being adjacent to the then existing PanCanadian Morley Gas Plant. However, the applicant subsequently decided not to proceed with the project at that time because of unfavourable economic conditions.

The applicant stated that various pipeline corridors and pipeline routes within the preferred corridor had been evaluated, with the preferred (applied-for) route selected based on environmental and technical considerations as well as landowners' preferences. Emergency shut-down valves (ESDVs) would be placed so that the sour gas pipeline would be a Level 2 pipeline*. The pipeline would meet all setback requirements from existing facilities.

The applicant held three public meetings between July and October 1988 to provide information to the area residents and an opportunity for them to comment on the project.

The applicant stated that as of the hearing date, easements had been obtained from all of the landowners or occupants whose land would be traversed by the applied-for pipeline except Mr. McParlane, Miss Hammond, Mrs. Philp, and Dr. Hess.

2 PRELIMINARY MATTERS

2.1 Safety

Several of the interveners expressed concern about their safety while living in close proximity to the proposed sour gas pipeline. While the Board accepts this as a legitimate concern, it notes that the proposed pipeline facilities will conform to all the necessary standards and requirements for sour gas operation. These have been designed to ensure the public's safety. In addition, Phillips proposes to install a supervisory control and data acquisition (SCADA) system on the pipeline which will include H_2S monitoring sensors at each well site, pipeline heater, and ESDV location. Phillips indicated that this SCADA system would be a first in the industry for the type of gathering system and transmission line proposed. Phillips also proposes to perform regular inspections on the pipeline for internal and external corrosion.

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*ERCB Interim Directive ID 81-3, "Minimum Distance Requirements Separating New Sour Gas Facilities from Residential and Other Developments", 16 December 1981.

To assure adequate contingency plans exist in the event of an accidental failure of the pipeline, Phillips must submit an appropriate emergency response plan to the Board for approval to operate the pipeline. The Board further notes that Petro-Canada has an existing emergency response plan filed with the Board for its Wildcat Hills Gas Plant which covers some of the area affected by the Phillips pipeline. Phillips must ensure that its emergency response plan is co-ordinated with Petro-Canada's plan. It will also consult with the municipal districts of Bighorn and Rockyview and local residents during the development of its emergency response plan.

Given the above, and given the overall safety record of sour gas pipeline operations in the province of Alberta, the Board is satisfied that this pipeline can be operated with little risk to the public.

2.2 Separation Distances

There was a great deal of discussion by the interveners about sour gas setback distances and how they would affect the interveners' use of their lands.

Many landowners perceive sour gas pipelines to be potentially dangerous. However, the Board believes that the pipelines are not dangerous when they are constructed and operated properly, although they can represent some risk to the public in the case of a pipeline break. While experience has shown that pipeline incidents which pose any public risk are rare, it is important to recognize the risks involved and provide a measure of public safety.

In order to provide increased public safety, the Board has prescribed certain minimum distance requirements separating proposed sour gas facilities from residential and other surface developments. These requirements were established having consideration for the likelihood of events actually happening, as well as for the magnitude and impact of the event. The actual separation (or "setback") distances were selected using a combination of predicted atmospheric dispersion behaviour, risk assessment methods, judgement based on sour gas releases from blowouts and pipeline ruptures, and the results of field tests of ground-level releases.

For the purpose of establishing a practical policy, sour gas pipelines were grouped into levels in accordance with their capability to release sour gas in case of a leak or rupture. A Level 1 pipeline has a potential to release 300 cubic metres (m^3) of H_2S or less. No minimum setback was established for Level 1 pipelines. A Level 2 pipeline has a potential to release more than 300 m^3 and less than 2000 m^3 of H_2S. The minimum setback for a Level 2 pipeline was set at 100 metres (m) for individual dwellings and 500 m for urban centres and public facilities.

Not every facility that is open to the public is classified as a "public facility" for the purposes of prescribing minimum separation distances when locating a proposed sour gas facility. Rather, the classification of a facility as a "public facility" is made having regard for such criteria as the number of people using the facility, the frequency and duration of its use, and the ease with which evacuation could be accomplished in the event of a sour gas release.* For example, Beaupre Hall is a rural community hall and would not normally be classified as a "public facility" for sour gas separation distance purposes because it has limited use and short-duration attendance, and because evacuation could be accomplished easily.

It is acknowledged that setback distance requirements may restrict future surface development. This is because the legislation governing subdivision approvals requires setbacks for the proposed surface developments which are similar to the separation distances prescribed by the Board for locating or routing sour gas facilities near existing surface developments. The subdivision legislation contemplates that the subdivision-approving authority will seek the Board's advice where a subdivision application involves land in the vicinity of a sour gas development. In most circumstances, the ERCB would not recommend, and the surface planning authorities would not permit, surface developments which resulted in people living within a prescribed sour gas setback. Accordingly, in situations where there has been a high potential for actual land-use conflicts, special measures such as the installation of sectionalizing valves on the pipeline have been devised to foster successful concurrent development of the surface and subsurface resources.

3 ISSUES

After a careful review of the evidence provided at the hearing, the Board believes that its consideration of the applications must first address the need for the pipelines. If the need exists, then a route must be sought based on a variety of criteria considered appropriate to evaluate the merits of the route selected.

Pipeline route selection must be a process of examining alternatives in progressively greater detail, in somewhat of a hierarchical fashion. If at any time an unacceptable impact is identified, then the selection

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*ERCB Interim Directive ID 87-2, "Sour Well Licensing and Drilling Requirements", 3 June 1987 as amended, at pages A1-2 and A1-4, provides some examples of "public facilities" for sour gas separation distance purposes.

process must be reversed and other alternatives re-examined. Every alternative cannot be evaluated to the same degree of detail, as there are infinite variations. In the final analysis the Board does not support moving the pipeline to favour one group of landowners to the detriment of another group.

For consideration of these applications, the Board considers it appropriate to first consider the choice of pipeline corridor which offers the most promise, and then the route itself.

The Board believes the issues for consideration of these applications to be

- o the need for the pipelines,
- o corridor selection, and
- o route selection.

4 NEED FOR THE PIPELINES

4.1 Views of the Applicant

Phillips stated that the applied-for pipelines are needed to transport sour gas production from the Salter Field to the Wildcat Hills Gas Plant for processing and sale. While there is no commitment date under the sales contract, the letter of intent between Phillips, Petro-Canada, and the other owners of the gas plant calls for a 1 November 1989 start-up. Any delay will likely significantly affect Phillips' construction schedule and result in potential lost revenues.

Phillips claimed that as a resource owner it has the right to develop its commercial discoveries, such as the Salter Field, provided that it can be done in a socially acceptable manner. Phillips studied three development scenarios, those being to build a new gas plant near the Salter Field, to build a gas plant on the site of the former PanCanadian Morley Gas Plant, and to pipeline the gas to an existing gas plant in the area with surplus capacity to process the Salter Field gas. Phillips rejected the first two options as they would result in a proliferation of gas plants and increased sulphur emissions. It also indicated that the old PanCanadian site is no longer available since houses have been erected on the site.

Phillips adopted the last option since the Petro-Canada Wildcat Hills Gas Plant is the only gas plant in the proximity of the wells that has surplus capacity to accommodate the total Salter Field production. Phillips pointed out that as an added benefit resulting from the selection of this plant, plant modifications and improvements would be required and could be economically justified, which would result in reduced sulphur emissions. This option requires the construction of the applied-for pipelines.

Petro-Canada supported the subject applications and stated that the proposed pipeline would eliminate the need for another sour gas plant in the Salter Field, thus preventing proliferation of gas processing facilities, and affording the opportunity to modify the existing plant such that current sulphur emissions from the plant would be substantially reduced.

Calgary Regional Planning Commission supported Phillips' applications subject to the condition that the Board is satisfied that provision has been made by the applicant for the safe construction and operation of the pipeline and ancillary facilities.

The Municpal District of Bighorn did not object to the subject pipelines; however, it requested the applicant be responsible for any upgrading of municipal facilities such as roads which may require improvements or changes as a result of the pipeline, be required to develop an emergency response plan in conjunction with the Municipal District of Bighorn, and have it in place prior to operating the pipeline.

4.2 Views of the Interveners

The interveners generally did not question the need for a pipeline for the production of the Salter Field wells, although some did suggest that processing the gas at a new plant located at the site of the former Morley Gas Plant would be preferable.

4.3 Views of the Board

The Board is satisfied that there is a need for Phillips to develop the Salter Field to meet its sales gas contract and that the processing plant option Phillips has adopted is the most orderly and provides the greatest benefit. Therefore, the Board is satisfied that pipelines are required to connect the wells in the Salter Field to the gas plant.

5 CORRIDOR SELECTION

5.1 Views of the Applicant

Phillips stated that it had conducted a detailed study of three pipeline corridors: southern, central, and northern, as shown on the attached Figure 2. Phillips considered pipeline length, terrain, residential density, effects on environment, and landowners' concerns to be the major factors in its evaluation of the corridors.

Phillips rejected the northern corridor because it is relatively close to the Waiparous and Benchlands country residential communities,

requires three difficult water crossings (Ghost River, Lesueur Creek, and Waiparous Creek), and would be located for much of its route in or near the environmentally sensitive Ghost River Valley. It would also result in the longest pipeline, and therefore the greatest linear disturbance (28.5 km).

Phillips considered the southern corridor unacceptable because it traverses the Morley Reserve, which has the highest number of rural residences generally distributed along the route, passes in close proximity to the summer village of Ghost Lake, and results in the second longest pipeline (27.5 km).

In response to Dr. Crowther's expert evidence, Phillips argued that the southern corridor would cross extensive side slope and bedrock areas, a subtantial part of which would probably require blasting. Phillips stressed that the construction of the pipeline and subsequent reclamation of the right of way within the southern corridor would be very difficult and relatively costly, and could result in lasting environmental effects. Phillips was confident that its evaluation of the southern corridor was sufficiently detailed to permit it to accurately assess its relative merits. Furthermore, Phillips noted that selection of the southern corridor would require that the pipeline between the 4-36 and 15-24 wells would need to be 168.3 mm OD, resulting in greater cost, and that the location of future field-gas compression facilities would have to be downstream of the 15-24 well, which could result in less than optimum ultimate gas recovery from the more northerly wells in the field.

Phillips concluded that the central corridor is the most viable one. Phillips noted that it is most direct to the gas plant and avoids densely populated country residential areas. It also results in the fewest environmental impacts since it has shorter bedrock and side slope distances than the southern corridor, and the least linear disturbance because of its shortest pipeline length (27.0 km).

5.2 Views of the Interveners

The interveners did not question the rejection of the northern corridor, and generally accepted the central corridor as a feasible route. However, Mr. McParlane argued that the southern corridor was not studied in sufficient detail and that a somewhat modified southern corridor (Crowther's route, Figure 2) would offer advantages similar to the central corridor while having less impact on residents.

Dr. Crowther, on behalf of Mr. McParlane, argued that the Kangienos Lake area along the southern corridor was not significant to waterfowl or fish species. He argued that there were no known archaeological sites recorded in the area. He stated that the area was inhabited by birds, probably of the passerine and migratory variety, and that with proper

timing, pipeline construction through this area would not be a significant restraint towards route selection. Dr. Crowther felt that the pipeline should be extended to a point south of Kangienos Lake and Pringle Mountain, then through a sparsely populated area on the Stoney Indian Reserve lands, and finally connected to the central corridor as shown in Figure 2.

While acknowledging that there would be some construction and reclamation concerns due to bedrock and side slopes in certain areas, Mr. McParlane argued that the southern corridor would significantly reduce the social concerns which would otherwise be caused by the applicant's preferred corridor. He questioned whether the environmental impact of the southern corridor is of higher concern than the social impact attendant to the applicant's preferred corridor. Representatives of the Morley Band rejected the location of the pipeline through the reserve.

Mr. McParlane also argued that the southern corridor was once considered a viable route and was included for assessment purposes in Phillip's Morley Gas Plant application in 1980, and that it should not be excluded from the process of detailed corridor selection.

5.3 Views of the Board

The Board believes that the main factors for the selection of the pipeline corridor are operational effectiveness, environmental effects, social concerns of the landowners, and costs. The Board accepts that the northern corridor is not desirable for the reasons identified by Phillips. The Board is also satisfied that sufficient information is available about the southern corridor, including the variation proposed by Dr. Crowther, to be able to reasonably compare it to the central corridor. Considering the above criteria, the Board is not convinced that the southern corridor would be preferable. The Board is satisfied that the southern corridor has a relatively high population density as it passes through the Morley Reserve and is in close proximity to the summer village of Ghost Lake and Highway 1A. The Board sees no apparent advantages to relocating the pipeline into the southern corridor as it would simply shift the associated social concerns to different landowners and residents. The Board is also satisfied that the additional length and complex construction terrain in those areas where the route would be close to Pringle Mountain, would cause a greater environmental impact than would occur in the central corridor. Therefore, the Board accepts the selection of the central corridor as the preferred alignment for the proposed pipeline.

6 ROUTE SELECTION

As illustrated in Figure 1, three areas of concern were identified along the central corridor:

- o the Ghost River/Spencer Creek area,
- o the Baymar Creek/Jamieson Road area, and
- o the Richards Road/Kangienos Lake area.

Each of these will be considered separately.

6.1 Ghost River/Spencer Creek Area

6.1.1 Views of the Applicant

Phillips stated that the applied-for route traversing Dr. Hess' property (Spencer Creek Ranch) would result in less environmental impact than other alternatives in the area. It would generally follow quarter section lines, avoid beaver dams and Beaupre Lake, and cross Spencer Creek perpendicularly rather than traversing laterally along the side slopes. Phillips also stated that the applied-for route would be the most direct from the Ghost River crossing to the plant and would not pose a safety hazard to residents, since it would exceed by a substantial margin the setback requirements for individual residences. Phillips argued that a desire to increase the comfort level for a resident or landowner was not an adequate reason to relocate the pipeline.

With respect to the selection of the Ghost Reservoir crossing, and the portion of the route immediately east of it, Phillips stated that it had considered six alternatives. Based on a detailed environmental study, it had selected the applied-for crossing after considering optimum crest-to-crest distance, site access conditions, pipeline length, and environmental and social impacts. Phillips stated that one of the major concerns of landowners Miss Hammond and Mrs. Philp was the preservation of trees, and that Phillips had accommodated their concern by routing the pipeline along the south side of the road within Miss Hammond's property.

In response to concerns raised at the hearing that the proposed alignment in the Hammond property would require some additional tree clearing, Phillips acknowledged that the pipeline could be located north of the road without serious environmental effects.

Phillips also argued that given the low reservoir level at this time, construction of the pipeline across the Ghost Reservoir should take place prior to spring runoff to avoid excessive environmental effect. It noted that TransAlta Utilities Corporation is presently raising the height of the dam, and that construction of the pipeline in the fall when the water level would be much higher would be more difficult and expensive.

6.1.2 Views of the Interveners

Dr. Hess' main concern is the risk associated with the applied-for pipeline being located only 200 m from her home. She stated that the pipeline would represent some on-going psychological stress and prevent her staying at her residence. She argued that the sour gas pipeline would adversely affect her ranching operation and potentially restrict her future use of her property. Dr. Hess proposed that the pipelines should follow the existing Petro-Canada water pipeline right of way north of her property or alternatively parallel the northern boundary line of her property where there are fewer trees and the slopes are more gentle. On behalf of Dr. Hess, Dr. Crowther stated that from the viewpoint of environmental impact and land disturbance, the routes proposed by Dr. Hess are as acceptable as the applied-for route. Dr. Crowther acknowledged that the proposed routes could affect Miss Hammond's parcel in the northwest corner of NW 1/4-19-26-5 W5M. Miss Hammond was strongly opposed to Dr. Hess' proposed route which would be near her land. Dr. Hess requested that if the pipeline is approved, it be conditioned on the resolution of an acceptable route as presented in her submission.

Mrs. Dubois, a resident on the Hammond property, argued that the applied-for route along the south side of the diagonal road on the property would result in the removal of mature trees and possibly disturb the marsh area adjacent to it. She was also concerned that if the east bank of the Ghost Reservoir was cleared and levelled at the pipeline crossings, more boaters would gather there to camp and litter. Mrs. Dubois suggested that the Ghost Reservoir crossing should be routed to the south side of the fence line between Miss Hammond's and Mrs. Philp's properties and along the south of the marsh area, or as proposed by Phillips across the Ghost Reservoir and then along the south side of the marsh area, or as a third option follow the applied-for route but along the north side of the diagonal road. She requested that if the application is approved, Phillips should consult her prior to any blasting of the Ghost Reservoir crossing and any herbicide spraying on the pipeline right of way, and that Phillips should ensure that the herbicides are sprayed under optimum wind conditions so that they do not seep into the marsh area. Mrs. Dubois was absolutely opposed to all routings traversing the main marsh area.

Mrs. Philp, owner of SW 1/4-24-26-6 W5M, was concerned about the potential increase in the amount of traffic, vandalism, and trespassing near her residence during and after the construction of the pipeline. She was also concerned about land disturbance on the pipeline right of way, especially in the wooded area north of her northern boundary line. She argued that regrowth would be difficult and uneconomical. Mrs. Philp was opposed to any sour gas pipeline traversing her property.

Mr. Herring, owner of NE 1/4-24-26-6 W5M, was concerned about seedlings planted as a future shelter belt along the southern boundary of his property. He was satisfied that modification of the Phillips proposed route that would cause it to run along the north side of the diagonal road on Miss Hammond's property would not impact his trees. He was also satisfied with that portion of the proposed route which would run on the south side of the road along the southern boundary of his property. He requested that if the pipeline were approved, the ESDV should be located in an innocuous location near the Ghost Reservoir to minimize vandalism.

6.1.3 Views of the Board

The Board believes that landowners' concerns should be resolved if it is possible to do so without causing more severe adverse situations. The Board also accepts the argument that pipelines should be routed along section lines unless offsetting advantages exist. The Board is satisfied that Dr. Hess' concerns cannot be resolved without more severe offsetting social, environmental and economic effects. Both of Dr. Hess' proposed routes would significantly affect Miss Hammond's parcel, would result in additional environmental impacts due to the crossing of Spencer Creek and the wetlands near Beaupre Lake and, because of their greater length, would be more costly. As noted earlier, the Board is satisfied that the existing setback criteria for sour gas pipelines are appropriate.

Given the evidence and site visit, the Board believes the proposed crossing of the Ghost Reservoir is the most suitable of all the available options. However, if the pipeline is approved, the Board will require Phillips to ensure that the riverbank restoration will not improve shore access to boaters. The Board will also instruct ERCB personnel to inspect these measures once they are installed. The Board believes that a pipeline route to the south of the marsh area would result in a new disturbance, whereas a route adjacent to the existing road would minimize environmental effects. The Board notes that the route along the north side of the diagonal road, when compared with that along the south side of the road, was generally accepted by both the applicant and the interveners. If the pipeline is otherwise approved, the Board would only approve this portion of the route if Phillips amends its application to reflect a suitable pipeline route adjacent to the north edge of the road and crossing to the south side of the road at the southeast corner of NW 1/4 24-26-6 W5M. Phillips would be required to notify the occupants in NW 1/4 24-26-6 W5M prior to any blasting required for pipeline construction through sandstone areas near or within the Ghost River and to ensure that there is no risk to their livestock.

Phillips would also be required to notify the occupants in the Hammond property prior to any herbicide spraying and to ensure that the herbicide is sprayed in such a way that it does not adversely affect the marsh area. Phillips would be required to ensure that all impacts on the marsh area by the pipeline construction are minimized. The Board would also request Phillips to take whatever measures are necessary to maintain existing drainage patterns for the trees and marsh area on the Hammond property after installation of the pipeline.

The Board is satisfied that there would be considerable environmental and cost advantage to build the Ghost Reservoir crossing prior to spring runoff and would urge this construction take place in May 1989, if the pipeline is approved.

6.2 Baymar Creek/Jamieson Road Area

6.2.1 Views of the Applicant

Phillips stated that the applied-for route has been selected over other locations for its environmental and technical advantages as well as landowners' preferences. Phillips believes that a pipeline adjacent to quarter section lines is fair to landowners on both sides of the pipeline and minimizes their concerns about land use. Phillips stated that the applied-for route has exceeded all the setback requirements and that it would pose fewer construction problems as it avoids side slopes near Baymar Creek and sandstone areas north of Mr. Schoustal's property.

6.2.2 Views of the Interveners

Mr. Schoustal was concerned about his family's safety in case of a pipeline leak. He also argued that his water well may be disturbed by sandstone blasting during pipeline construction and that his future residential and possible commercial development plans would be adversely affected by the setback requirements of the applied-for route.
Mr. Schoustal suggested that the pipeline should be re-routed across the NE 1/4 30-26-6 W5M where the elevation is higher and where it would be farther from his water supply.

Mr. Fish proposed that the pipeline should be moved 100 m north of his property line or that additional ESDVs should be installed to eliminate the setback requirements.

Mr. MacGregor, owner of SW 1/4-28-26-6 W5M, was generally in favour of the proposed route.

Mr. Thomas, owner of SW 1/4-33-26-6 W5M, did not object to the applied-for route; however, he was not satisfied with Phillips'

emergency response plan and urged that such a plan should be satisfactorily in place prior to the start of operation.

McDougall Ranches, which owns the land adjacent to Mr. Fish, objected to the location of the pipeline anywhere other than along the quarter section line. It argued that to locate the pipeline otherwise would prevent ultimate development of the property and reduce its resale value inordinately.

6.2.3 Views of the Board

The Board believes that it is generally preferable to locate the pipeline along property lines where the impacts of a linear disturbance are minimized by avoiding fragmenting of properties (typically, quarter sections) and a portion of the setback is already set aside by the municipal authorities.

The Board is satisfied that the applied-for route in the Baymar Creek/Jamieson Road area would locate the pipeline more than 100 m from any existing residence, as prescribed by the minimum separation distance requirements set out in the Board's Interim Directive ID 81-3. On the evidence before it, the Board is also satisfied that the applied-for route would not impact any immediate plans for surface development. It notes that Mr. Fish has no current plans to develop his property. It also notes that although Mr. Schoustal has a preferred site for his future residence, he has not yet identified any specific plans for his proposed residence or for any other possible developments on his land, nor has it been established that the local municipal authorities would prohibit surface development on any particular site because of the existence of the proposed pipeline.

Nevertheless, as indicated in Section 2 of this decision report, the Board acknowledges that the existence of a sour gas facility may restrict future surface development in specific situations. The Board believes that both the surface land user and the resource developer should take all reasonable and practicable steps to mitigate such potential land-use conflicts so that concurrent development can proceed successfully. It also notes that existing legislation authorizes the Board to require a pipeline to be modified or relocated where the Board is satisfied that it is in the public interest to do so. Any such matter would be the subject of a future application to the Board for its consideration at that time based upon the circumstances as they then existed.

In regard to Mr. Schoustal's concern about potential disturbance to his water well by the pipeline construction, the Board notes that a water well restoration program is available to assist people who believe their wells have been damaged by petroleum industry activities. The office of the Farmer's Advocate is responsible for administering the program.

The Board is satisfied that Phillips will have in place a suitable emergency response plan prior to the start-up of the pipeline operation. That plan will be reviewed by the ERCB to ensure that the concerns of Mr. Schoustal and Mr. Thomas have been specifically addressed.

6.3 Richards Road/Kangienos Lake Area

6.3.1 Views of the Applicant

Phillips believed that the applied-for route would result in the least linear disturbance and fewer environmental effects than other alternatives in the area as it avoids Kangienos Lake and Pringle Mountain. Phillips also argued that the applied-for route would satisfy all the setback requirements for individual residences and cause fewer concerns to the landowners on both sides of the applied-for route since it generally follows section lines.

Phillips argued that it had studied all alternative routes in sufficient detail to confidently state that the applied-for route is the best alternative, considering all route selection criteria. Phillips stressed that there was no net advantage to other routings or to further studies of other routings. Phillips concluded that other pipeline routes would be more difficult to construct and that there would also likely be new landowner objections.

In response to Mr. Kun's suggestions, the applicant carried out a field inspection between 7 and 16 March and concluded that the corridor suggested by Mr. Kun did not offer a better route alignment than the proposed route. It argued that the Kun corridor was longer, more costly, and less environmentally desirable because of Kangienos Lake and the residences in the vicinity.

6.3.2 Views of the Interveners

Mrs. Dawson stated that she had subdivided some of her property west of Richards Road and recently sold the parcels to people who want to build country residential dwellings. Mrs. Dawson suggested that the applied-for route would affect such development plans, and to avoid this a pipeline corridor south of Kangienos Lake should be further studied to assess its feasibility. Mrs. Dawson also indicated that based on her discussions with the residents affected, she would not expect landowner resistance to a route aligned along the Kun corridor.

Mr. McParlane stated that he has plans to develop and operate his property as a fitness retreat which would include building clusters of small chalets and other related fitness amenities to provide temporary accommodation for single-parent families. He stated that the ideal site for such a development would be the area within approximately 100 m of the south boundary of his property. He argued that the preferred

route, if approved, would greatly reduce his usable land space. Mr. McParlane preferred to have the pipeline re-routed elsewhere. Mr. McParlane requested the denial of the applied-for pipeline until other alternatives are determined not to be in the public interest. If the application is approved, Mr. McParlane requested that the pipeline be upgraded to Level 1 so that his development plans would not be hindered, and that Phillips be required to negotiate the right of way in accordance with section 11.(2) of the Pipeline Act.

Mr. Ingram stated that the 500-m setback for a public facility from a Level 2 pipeline would extend into his property. He argued that he is planning to build a permanent residence and possibly a riding stable and that a sour gas pipeline so close to his property would affect his lifestyle in terms of security, safety, and property value. Mr. Ingram proposed that the pipeline should be moved farther south. However, if the pipeline is approved, Mr. Ingram requested that access to the pipeline right of way from Richards Road be prevented. He also supported Mr. McParlane's request for additional ESDVs.

Mr. Kun bought his property with the intention of developing it into a livestock operation and a possible commercial tourist facility. He also planned to build a permanent residence for retirement. He stated that the most desirable site for his future home would be the extreme northwest corner of his property which is well within 100 m of the applied-for route. He argued that the applied-for route, if approved, would shatter all his plans and investment. Mr. Kun suggested that the pipeline should be re-routed to a corridor south of Kangienos Lake and then follow the existing seismic cut lines as shown in the attached Figures 1 and 2. He argued that Phillips has not done enough research in this area and that no approval should be granted without a thorough evaluation of the alternatives through this area.

6.3.3 Views of the Board

The Board is satisfied that Mr. Kun's proposed corridor merits further investigation to determine whether or not that alternative has advantages over the applied-for route. There appears to be contradictory evidence on landowner objections to the use of an alignment along the Kun corridor. The preliminary evidence presented suggests that Mr. Kun's corridor may alleviate some of the social concerns by interveners with the applied-for route without offsetting adverse effects. The Board is also concerned that it did not receive sufficient evidence as to the impact the proposed route would have on the propects for residential development within the Dawson property along Richards Road. The Board is not satisifed that Phillips has adequately considered this corridor. Therefore, if the pipeline is approved, the Board would withhold the route approval for the portions west of section 25-26-7 W5M until Phillips investigates and reports on all circumstances relevant to the corridor proposed by Mr. Kun (Figures 1 and 2) including, but not limited to, a cost comparison.

Such cost estimates should consider alternatives including summer and winter construction as well as the impact of installing ESD valves to accommodate future developments.

7 DECISION

The Board is prepared to grant Applications 882129 and 882130 by Phillips Petroleum Resources, Ltd. for the portion east of section 26, township 26, range 7, west of the 5th meridian, subject to the receipt of an amendment to the application to reflect the change in NW 1/4-24-26-6 W5M discussed in Section 6.1.3 of this report, subject to receipt of the approval of the Minister of the Environment respecting environmental matters, and subject to the conditions and restrictions as discussed in the body of this report.

The Board will defer its decision on routing west of section 25, township 26, range 7, west of the 5th meridian, until further evidence is submitted by the applicant respecting the corridor proposed by Mr. Kun.

DATED at Calgary, Alberta, on 2 May 1989.

ENERGY RESOURCES CONSERVATION BOARD

F. J. Mink, P.Eng.
Board Member

B. J. Morin, P.Eng.
Board Member

R G Evans

R. G. Evans, P.Eng.
Acting Board Member

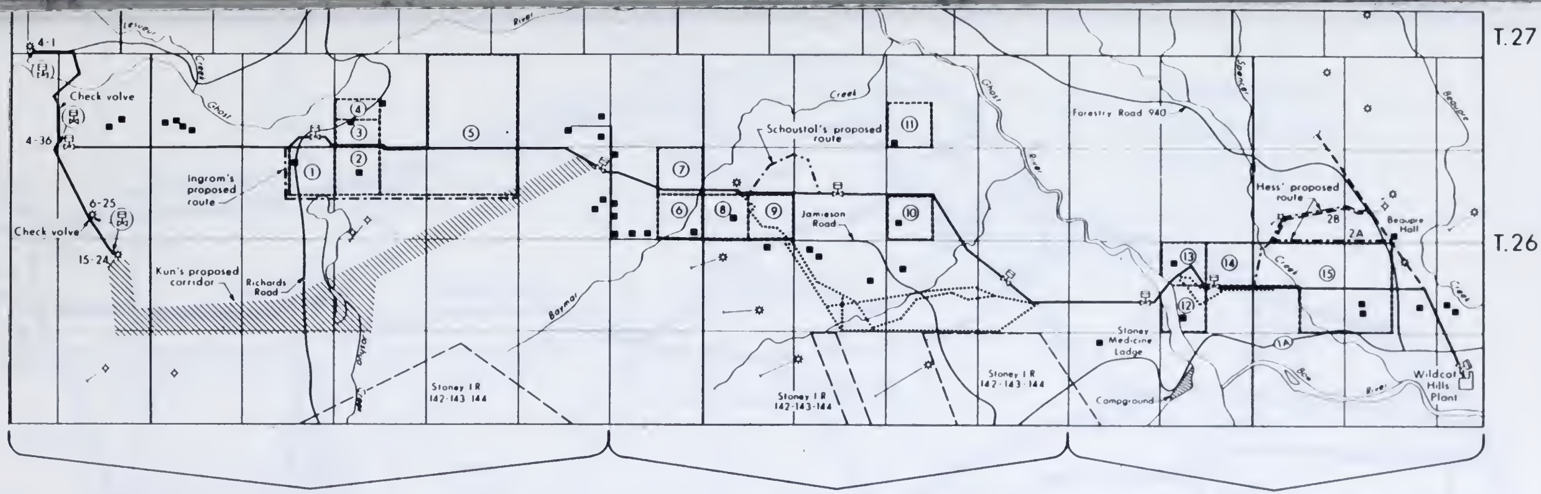
APPENDIX A

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Phillips Petroleum Resources, Ltd. (Phillips) A. L. McLarty	J. G. Greenslade, P.Eng. K. Bessie, P.Ag. of Western Research E. Wichert, P.Eng. of Sogapro Engineering Ltd. I. Jones, P.Geol. of Thurber Consultants Ltd.
Calgary Regional Planning Commission B. Koch P. Mercer	B. Koch
Municipal District of Bighorn No. 8 S. de Keijzer	S. de Keijzer
Petro-Canada Inc. (Petro-Canada) S. Miller	
F. Dawson	F. Dawson
W. H. Ingram B. Baltimore	W. H. Ingram
M. McParlane B. K. O'Ferrall J.E.E. Lowe	M. McParlane Dr. R. Crowther, P.Biol. of Aquatic Resource Management Ltd.
S. F. Kun	S. F. Kun
David H. McDougall Ranch Co. Ltd. G. McNabb, P.Eng.	G. McNabb, P.Eng.
J. R. Fish	J. R. Fish
W. B. Schoustal	W. B. Schoustal
J. MacGregor	J. MacGregor
R. Thomas	R. Thomas
M. Philp	M. Philp

Principals and Representatives (Abbreviations Used in Report)	Witnesses
G. Hammond K. F. Miller	P. Dubois
I. W. Herring, P.Eng.	I. W. Herring, P.Eng.
Dr. M. Hess (Spencer Creek Ranch) B. K. O'Ferrall J.E.E. Lowe	Dr. M. Hess Dr. R. Crowther, P.Biol. of Aquatic Resource Management Ltd.
Stoney Band of Indians R. C. Smith, Q.C.	
Alberta Environment R. Dyer	
Energy Resources Conservation Board staff A. A. Broughton T. J. Pesta, P.Eng. S. C. Lee, P.Eng. D. G. Beamer, R.E.T.	

L. Rasmussen filed a submission but did not appear at the hearing.



Richards Road/Kangienos Lake Area

Baymar Creek/Jamieson Road Area

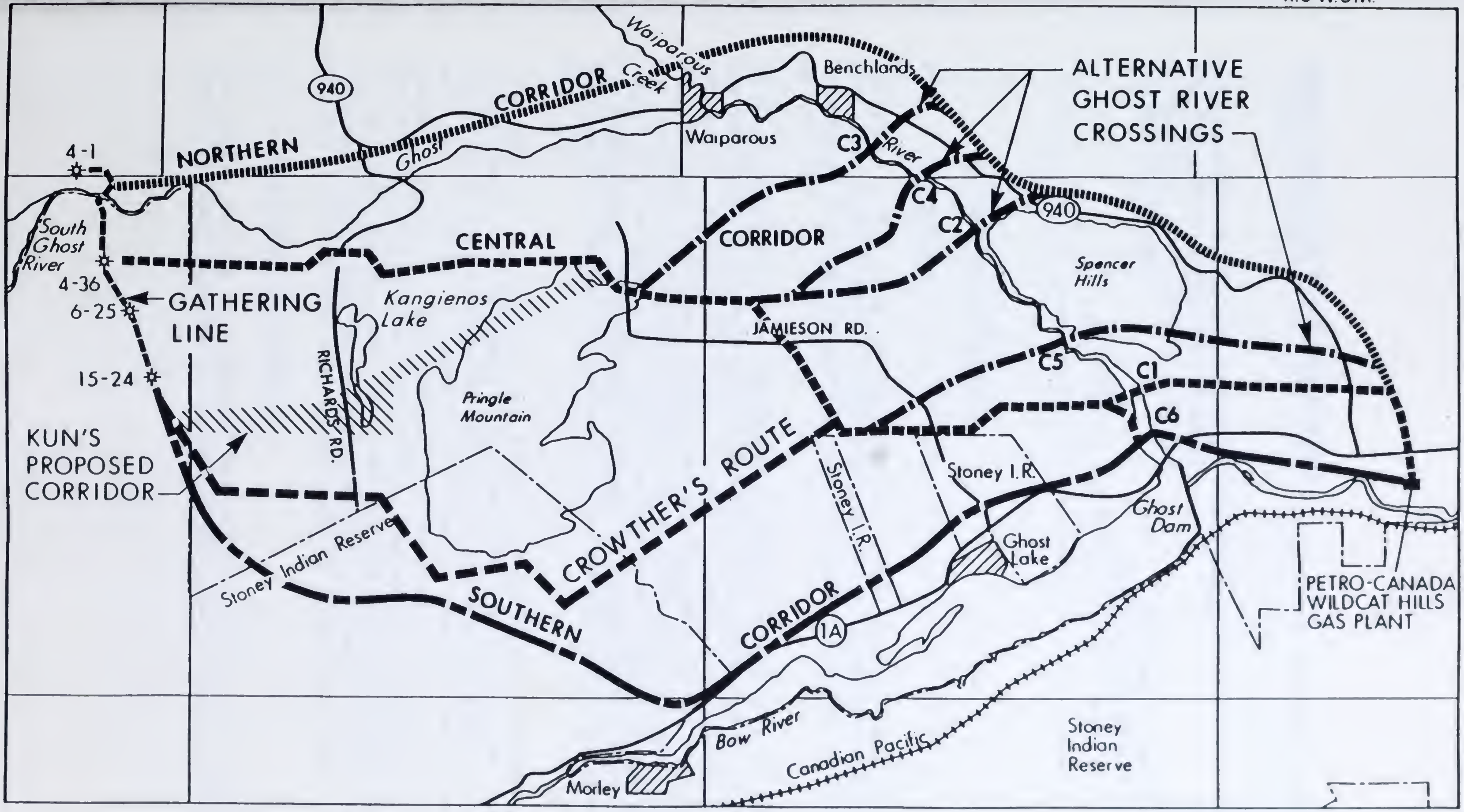
Ghost River/Spencer Creek Area

- Existing residence
- Preferred route
- Alternative routes
- Intervener's proposed routes
- Petrocan's existing R.O.W.
- Emergency shut down valve

Interveners' land

1. Mrs. Dawson
2. Mr. Kun
3. Mr. McParlane
4. Mr. Ingram
5. D.H. McDougall Ranch
6. Mr. Fish
7. D.H. McDougall Ranch
8. Mr. Rasmussen
9. Mr. Schoustal
10. Mr. MacGregor
11. Mr. Thomas
12. Mrs. Philp
13. Miss Hammond
14. Mr. Herring
15. Spencer Creek Ranch

FIGURE 1 PROPOSED PIPELINE ROUTES
Applications No. 882129 & 882130
Phillips Petroleum Resources, Ltd.



✲ Phillips gas wells

FIGURE 2 PIPELINE CORRIDORS
Applications No. 882129 & 882130
Phillips Petroleum Resources, Ltd.

D89-4
ERCB

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

APPLICATIONS BY PHILLIPS PETROLEUM RESOURCES, LTD.
FOR PERMITS TO CONSTRUCT PIPELINES
TO TRANSPORT SOUR GAS AND FUEL GAS
IN THE SALTER FIELD

Addendum to Decision D 89-4
Applications 882129 and 882130
Application for Review and Variance by Dr. M. Hess

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1 BACKGROUND INFORMATION

1.1 Background

Pursuant to Part 4 of the Pipeline Act, Phillips Petroleum Resources, Ltd. (Phillips) submitted Applications 882129 and 882130 which were considered at a public hearing held in Calgary, Alberta, in February and March 1989.

In ERCB Decision D 89-4, the Board approved construction of a portion of the preferred route between the Wildcat Hills plant and a point east of section 26, township 26, range 7, west of the 5th meridian. The Board deferred consideration of the proposed alignment of the pipeline west of that point until further evidence was submitted by the applicant respecting the merits of using an alternative alignment south of Kangienos Lake. This further evidence was filed by Phillips. The applied-for alternative, referred to as the Kun route, is shown in Figure 2.

Subsequent to its decision the Board also received a request, pursuant to section 42 of the Energy Resources Conservation Act, for a review and variance of its decision respecting the approved alignment on or near sections 19 and 20 of township 26, range 5, west of the 5th meridian, as shown in Figure 1. The land in question is owned by Dr. Hess. Counsel for Dr. Hess argued that the Board's reasons for approving the alignment on the Hess property were incorrect and may have been based on misleading testimony of a witness appearing on behalf of Dr. Hess. Given this uncertainty the Board agreed to review the matter.

1.2 Reopening of Hearing

The public hearing was reopened in Calgary, Alberta, on 9 and 12 June 1989 with Board Members F. J. Mink, P.Eng., E. J. Morin, P.Eng., and

Acting Board Member R. G. Evans, P.Eng., to consider the Hess review as well as the western alignment of the pipeline.

Participants at the hearing are listed in Appendix A.

2 REVIEW WITH RESPECT TO ROUTING ON DR. HESS' LAND

2.1 Dr. Hess' Views

As detailed in ERCB Decision D 89-4, the Board approved the routing on or near Dr. Hess' land in the N 1/2 and SE 1/4-19-26-5 W5M and the W 1/2-20-26-5 W5M, hereinafter referred to as the "approved route".

Dr. Hess proposed that the pipeline should be routed to follow her proposed Route 2A (shown in Figure 1) as more clearly defined since the original hearing.

Dr. Hess argued that the Board's findings in Section 6.1.3 of ERCB Decision D 89-4 were based on a misapprehension of facts. She stated that Miss Hammond's 2-hectare parcel was not within 100 metres (m) of her proposed Route 2A and that it would not be significantly affected. Dr. Hess agreed to avoid impacts on adjacent landowners by aligning the pipeline far enough inside her property that any residential development setback requirements resulting from the pipeline would not extend onto her neighbours' lands any farther than existing municipal property line or road allowance setbacks now do.

She argued that the proposed Spencer Creek crossing along Route 2A would be no more difficult than the approved crossing since stream diversion in that area is very simple and would result in only minimal environmental impact. Dr. Hess acknowledged that the land disturbance along Route 2A was approximately 1 kilometre (km) longer than the approved route. However, she argued that the cover of Bow Valley soil along Route 2A was much thicker and was relatively free of rocks and gravel compared to the approved route. She also argued that the north side of Beaupre Lake was wetter, and presented evidence to show that the topsoil along Route 2A was thicker and as a consequence reclamation along Route 2A would be easier to accomplish. She noted that there would be little incremental effect on Beaupre Hall by her proposed Route 2A. Dr. Hess was also concerned that ranching operations on her land would be restricted by the fences which would be required on both sides of the approved route in order to prevent cattle from walking along the right of way during its reclamation.

2.2 Views of the Interveners

Mr. Holden (owner of a portion of E 1/2-20-26-5 W5M) favoured Dr. Hess' Route 2A because it would impact his property less at the north end than

the approved route. Mr. McLenahan (owner of a portion of NE 1/4-20-26-5 W5M) also expressed support for Route 2A because it would allow him to build closer to his south fence where it is rather heavily treed and much more viable as a future building site. McDougall Ranch (lessee of SW 1/4-19-26-5 W5M) did not object to Route 2A.

Mr. Bowlen (owner of SW 1/4-29-26-5 W5M) indicated that soil conditions were extremely poor throughout the area and suggested that he would not differentiate soil qualities between Route 2A and the approved route. However, he stated that he would not object to Route 2A if it did not affect his land.

Rocky View School Division No. 41 (owner of a 0.76-hectare parcel in SW 1/4-29-26-5 W5M) opposed Route 2A. It noted that its property has recently been offered for sale and argued that Route 2A would impose a sour gas pipeline setback upon its property that would substantially reduce its value for residential use. In the absence of such a sour gas pipeline setback, the School Division was advised it could get a relaxation of the existing municipal setback to permit a residental building on its parcel.

Mr. Herring (owner of NE 1/4-24-26-6 W5M) objected to Route 2A. He argued that Route 2A, which parallels the only egress from his property, would add substantial extra risk and that it "would basically destroy the property's use for the purpose" which he had intended.

Mr. Barrett, on behalf of Beaupre Community Association which maintains Beaupre Hall located in SE 1/4-29-26-5 W5M, objected to Route 2A since the pipeline would be less than 500 m away from the hall. He submitted evidence to show that the facility was used far more extensively than indicated by Dr. Hess at the earlier part of the hearing. He was concerned that restrictions may be placed on the use of Beaupre Hall, including its use as a playschool which accommodates up to 25 children, if Route 2A were adopted. He was also concerned about the potential hazard in case of a line break or leak to the west of Beaupre Hall.

Mrs. Philp was concerned about environmental effects of the pipeline in general and she preferred Route 2A.

In a letter to the Board, Alberta Environment indicated it had no preference between the two pipeline routes.

2.3 Phillips' Views

Phillips argued that the south side of Beaupre Lake where the approved route would traverse was no more environmentally sensitive than the north side. Phillips claimed that the approved route was preferable because the crossing of Spencer Creek would be easier, and reclamation would also be easier because of the nature of the "Lloyd Lake" type topsoil along part of the approved route. Phillips claimed that the

extent of the "Bow Valley" type topsoil along most of Dr. Hess' route would make it more difficult to reclaim. Phillips argued that because Route 2A was longer, it would result in larger disturbance and reclamation area, would require the relocation of the emergency shutdown valve (ESDV) farther from the Ghost Reservoir Crossing, would require an increase in the size of the gathering pipelines, and would, consequently, increase the costs of the pipeline.

2.4 Views of the Board

Dr. Hess applied to the Board for a review and variance of the decision with respect to the part of the route running through her property. In her application, Dr. Hess raised three issues which, in her opinion, justified variance. These issues were the relative difficulty of constructing and reclaiming the land along the pipeline route across the north end versus the south end of Beaupre Lake, the relative ease with which a pipeline could be constructed across Spencer Creek on the two routes, and the impact, if any, upon the Hammond property caused by Dr. Hess' proposed Route 2A. During the hearing, three additional issues which the Board judges to be of significance were raised and discussed at some length. Those issues were the relative impact of the two routes upon the lands of other nearby landowners, the relative ease with which reclamation could be carried out upon Route 2A and the approved route, and the supplemental costs to the pipeline company associated with the longer length of pipe and the larger diameter of pipe which would be occasioned as a result of the longer Route 2A. A fourth additional issue, which the Board judges to be relatively minor, is that of the impact on the ranching operations conducted on the Hess property because of the need to fence off the pipeline right of way during the period when reclamation is under way.

The Board has approached its analysis of these issues from the point of view that the evidence must show that the sum of all of these reasons is sufficient to cause it to vary its previous decision and has carefully considered all of the evidence submitted for that purpose. With respect to the impact on the Hammond property, the Board accepts that, on the basis of the new evidence regarding Route 2A, there would not be an impact on the potential for residential development on the Hammond property by Route 2A. The two routes are therefore equal in this regard.

The Board notes that construction along either alignment would be relatively easy by normal pipeline construction standards. With respect to the relative difficulties of the two creek crossings, the Board notes that on Route 2A, the creek valley has relatively steep sides, and the creek itself has a somewhat meandering nature. On the approved route, the creek is relatively straight. The Board is of the opinion that there would be less channel disturbance on the approved route. Therefore, on the basis of creek crossing difficulty, the Board

finds that there is not any reason to vary its decision. Similarly, the Board's judgement of the evidence presented is that the approved route, passing south of Beaupre Lake, would encounter relatively drier land and easier pipeline construction than would Route 2A to the north of the lake. This, also, fails to indicate a reason to vary the decision.

With respect to the ease of reclamation of the disturbed lands along the two routes, the Board notes that there was some measure of disagreement between the expert witnesses for Dr. Hess and Phillips regarding the relative ease of the reclamation on the soils of Bow Valley type along each route. On the basis of the evidence, however, both Dr. Hess' and Phillips' witnesses agreed that soils of the Lloyd Lake type should present fewer difficulties in reclamation than soils of the Bow Valley type. The evidence clearly indicates that on the Hess Route 2A, a total of 3800 m of pipeline would be constructed in soils of the more difficult to reclaim Bow Valley type, between the points where the two pipeline routes enter the northwest corner of the McDougall property, (marked point X on Figure 1) and the point where the two routes rejoin southeast of Beaupre Lake (marked point Z on Figure 1). On the approved route between the same two points, the pipeline would traverse a total of 600 m of the relatively easier to reclaim Lloyd Lake soil, and some 2400 m of the more difficult to reclaim Bow Valley soil. Hence, the Board judges that, notwithstanding any local differences in the sparseness of soil cover of a particular type along the two routes, the combined overall reclamation difficulty along the approved route would be no greater, and perhaps considerably less, than along the Hess Route 2A.

Two additional factors should be considered. Firstly, the Land Surface Conservation and Reclamation Council of Alberta's Department of the Environment supplied a letter stating that it took no position with respect to the reclamation of either of the routes. Secondly, the Board is satisfied that a pipeline could be constructed, and the surface disturbance reclaimed, along either of the routes. In total, the Board has concluded that there is no evidence with regard to reclamation capability sufficient to cause the Board to vary its previous decision.

The Board has noted the new evidence with respect to the use of Beaupre Hall. As previously indicated in Decision D 89-4, a rural community hall such as Beaupre Hall would not normally be classified as a "public facility" for sour gas separation distance purposes because it has limited use and short-duration attendance, and because evacuation could be accomplished easily. However, contrary to evidence provided by Dr. Hess at the earlier hearing, this particular hall appears to be used regularly and extensively. The Board is therefore concerned that location of another sour gas pipeline to within 500 m of Beaupre Hall would not be appropriate.

While the impact on the offset landowners would not be extensive, the Board notes that the rerouting along the Hess Route 2A is opposed.

In summary, the Board believes that shorter sour gas pipelines are generally preferable to longer sour gas pipelines unless material advantages exist to offset the extension. The Board is satisfied that Route 2A would be more costly as it is significantly longer and would require an increase in the size of the gathering pipelines. Route 2A would also result in a larger and more difficult area to reclaim. The Board is also convinced that the approved route reduces the public risk, and meets all its requirements. The Board also confirms its preference to route pipelines along quarter section or section lines rather than to traverse property as proposed by Dr. Hess. Having considered all of the above, the Board continues to believe the approved route is preferable through the Hess property, and is satisfied that on balance it should not vary its previous decision.

3 CONSIDERATION OF ROUTINGS WEST OF SECTION 25-26-7 W5M

3.1 Applicant's Views

In response to the Board's request for more information, Phillips evaluated four potential pipeline routes within the Kun corridor as detailed in Appendix 4 of the addendum to Applications 832129 and 832130. It found the more lengthy route around Kangienos Lake to be the best of the four alternatives within the Kun corridor. Although it is the longest of the routes, it minimized the requirement for ripping and blasting bedrock, minimized the length of slope which could present construction problems, and it avoided the landowner's concerns with the crossing of section 26-26-7 W5M. Hereinafter, this will for convenience be called the Kun route.

Phillips also performed a detailed comparison of the Kun route with the preferred route as shown in the attached Appendix B. The comparison shows that from environmental and economic perspectives the Phillips preferred route is clearly superior. The Kun route would be longer, would result in an increase in size of the gathering system pipelines, would be more costly, and would reduce ultimate gas recovery. Furthermore, selection of the Kun route would result in significant project delay since right of way agreements would have to be negotiated with the Stoney Indians.

Notwithstanding the above, Phillips has amended its application to also apply for the Kun route in case the Board found Phillips' preferred route unacceptable.

Phillips also submitted an amendment to the preferred route within sections 32 and 33-26-7 W5M, hereinafter referred to as the amended

preferred route, as shown in Figure 2. Phillips stated that there is no objection to this amended preferred route by landowners and land occupants within 500 m.

3.2 Interveners' Views

Mr. Kun, McDougall Ranch, and Mr. Seidel expressed support for the amended preferred route. Mr. Seidel (owner of NW 1/4 and S 1/2 of section 26-26-7 W5M) expressed opposition to an alternative route considered by Phillips which would traverse his property but indicated satisfaction with the amended preferred route. He would not be affected by the Kun route shown in Figure 2. Mr. McParlane's solicitor stated that Mr. McParlane found the amended preferred route acceptable.

3.3 Board's Views

Given the thorough investigation of alternative routes within the Kun corridor and the evidence presented on them, the Board is satisfied that the alternative selected by Phillips (the Kun route) is the most feasible within the Kun corridor. The Board accepts the analysis carried out by Phillips that in comparison with the amended preferred route, the Kun route would be longer, would require larger gathering lines and would result in significant additional costs, longer linear disturbance, and project delay which would negatively affect the economics of production. The Board notes that the owners of Mrs. Dawson's subdivided land did not object to the amended preferred route. The Board also notes that no landowners, occupants, or affected parties west of section 25-26-7 W5M object to the amended preferred route. Considering the evidence, the Board is satisfied that there are substantial disadvantages to the Kun route, without material offsetting benefits. Therefore, the Board concludes that the Phillips' amended preferred route is more feasible than the Kun route.

4 DECISION

Having considered all the evidence submitted, the Board decides

(i) that the original alignment as per ERCB Decision D 89-4 with respect to routing on or near Dr. Hess' land in sections 19 and 20 of township 26, range 5, west of the 5th meridian, is the most appropriate and is in the public interest and that the application for variance of that alignment is denied, and

(ii) that the Phillips' amended preferred route as per the addendum to Applications 882129 and 882130 by Phillips Petroleum Resources, Ltd. for the portion west of section 25, township 26, range 7, west of the 5th meridian, as identified

during the hearing, is approved, subject to the receipt of approval of the Minister of the Environment respecting environmental matters.

DATED at Calgary, Alberta, on 19 July 1989.

ENERGY RESOURCES CONSERVATION BOARD

P. J. Mink, P.Eng.
Board Member

E. J. Morin, P.Eng.
Board Member

R G Evans

R. G. Evans, P.Eng.
Acting Board Member

APPENDIX A

Review of Decision D 89-4 with Respect to Routing on Dr. Hess' Land

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Dr. M. Hess (Spencer Creek Ranch) B. K. O'Ferrall	Dr. M. Hess R. A. Berrien, P.Ag., A.R.A. of R. A. Berrien Associates (Rural) Ltd. Dr. R. Crowther, P.Biol. of Aquatic Resources Management Ltd. D. Dutchik
Phillips Petroleum Resources, Ltd. (Phillips) A. L. McLarty	J. G. Greenslade, P.Eng. K. Bessie, P.Ag. of Western Research
D. Holden	D. Holden
J. McLenahan	J. McLenahan
J. E. Bowlen	J. E. Bowlen
Rocky View School Division No. 41 G. Wilson	G. Wilson
I. W. Herring, P.Eng.	I. W. Herring, P.Eng.
Beaupre Community Association R. J. Barrett	R. J. Barrett
Alberta Environment R. Dyer	
M. Philp	M. Philp
D. H. McDougall Ranch Co. Ltd. G. McNabb, P.Eng.	G. McNabb, P.Eng.
Energy Resources Conservation Board staff A. A. Broughton T. J. Pesta, P.Eng. S. C. Lee, P.Eng. D. G. Beamer, R.E.T.	

Consideration of Addendum to Applications 882129 and 882130
(Western Portion)

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Phillips Petroleum Resources, Ltd. (Phillips) A. L. McLarty	J. G. Greenslade, P.Eng. I. Jones, P.Geol. of Thurber Consultants Ltd. D. Mutrie of TERA Environmental Consultants (Alta) Ltd. S. Schiller of Flint Engineering and Construction Ltd.
M. McParlane B. K. O'Ferrall	
F. Dawson	
S. F. Kun	S. F. Kun
D. H. McDougall Ranch Co. Ltd. G. McNabb, P.Eng.	G. McNabb, P.Eng.
Ghost Pine Lumber F. W. Seidel	F. W. Seidel
Alberta Environment R. Dyer	
Energy Resources Conservation Board staff A. A. Broughton T. J. Pesta, P.Eng. S. C. Lee, P.Eng. D. G. Beamer, R.E.T.	

COMPARISON OF PREFERRED AND ALTERNATE ROUTE
KANGIENOS LAKE/RICHARDS ROAD AREA

APPENDIX B

ITEM	PREFERRED ROUTE	BEST ALTERNATE ROUTE	DIFFERENCE
Length (m)	10,210	12,100	1,890
Muskeg:			
Shallow (m)	60	740	680
Deep (m)	690	810	120
Bedrock:			
Rippable (m)	2,710	4,590	1,880
Blasting (m)	0	0	0
Steep Slopes (m)	170	150	(20)
Tree Clearing (ha)	15.1	16.2	1.1
New Linear Disturbance (m)	1840	1940	100
Timing (months)	5	7 to 12	2 to 7
Incremental Cost: Winter		\$501,400	\$501,400
Summer		\$554,900	\$554,900
Road Crossings	2	4	2
Residences Number within 200 m	0	2	2
Potential H_2S Release Volume (m^3)	1770	1950	180
Environmental features	Close to Douglas Fir in NW 1/4-28-26-7W5M SW 1/4-33-26-7W5M	. Close to Kangienos Lake and Richards Lake . Crosses toe of Pringle Mountain	Minimal
Location of Future Compression	Central	South End	Better Ultimate Recovery
Landowner problems	none	two	No project delay or extra cost
Resident concerns	Along Richards Road	Minimal	(Social Concerns)

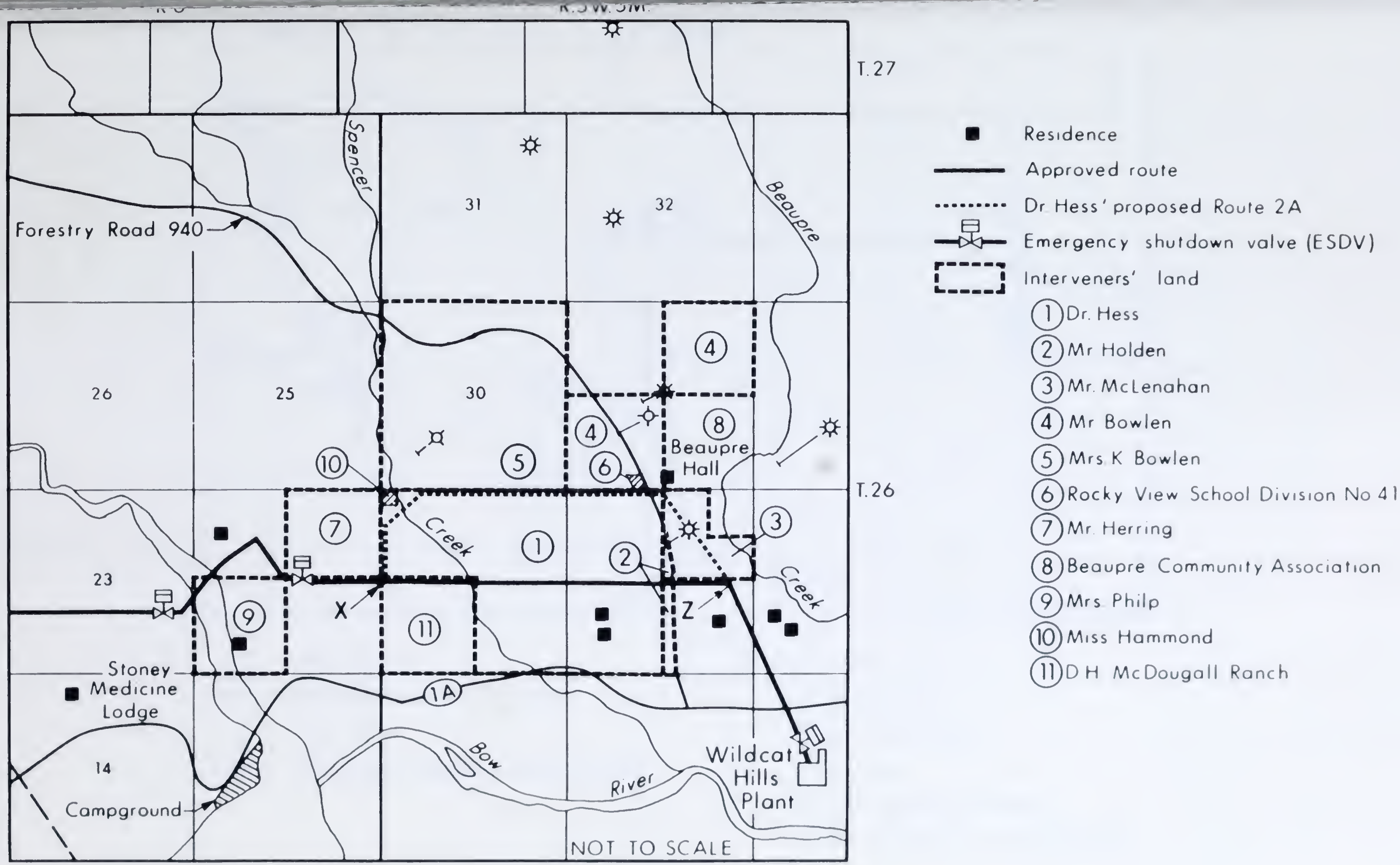

FIGURE 1 APPROVED AND PROPOSED PIPELINE ROUTES
Applications No.882129 & 882130
Phillips Petroleum Resources, Ltd.

Addendum to
D89-4
ERCB

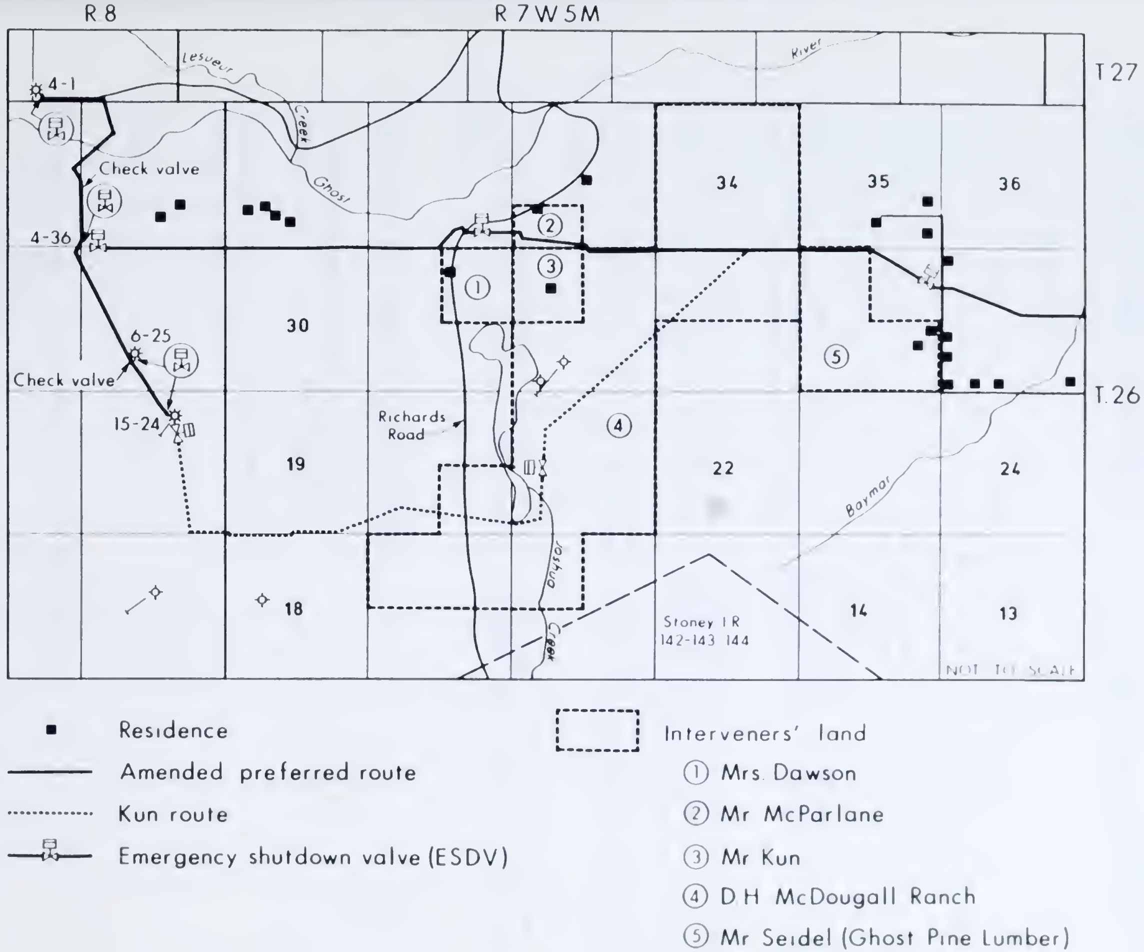

FIGURE 2 APPLIED-FOR PIPELINE ROUTES
Addendum to Applications No 882129 & 882130
Phillips Petroleum Resources, Ltd.

Addendum to
D89-4
ERCB

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

LOCAL INTERVENERS' COSTS RESPECTING SHELL CANADA LIMITED'S PRAIRIE BLUFF WELL LICENCE APPLICATIONS

Decision D 89-5
Applications 870417 and 870418

1 INTRODUCTION

On 10 June 1988, the Board, with G. J. DeSorcy, P.Eng., F. J. Mink, P.Eng., J. P. Prince, Ph.D., and E. J. Morin, P.Eng., sitting, considered at a hearing in Calgary a claim for an award of costs pursuant to section 31 of the Energy Resources Conservation Act (the Act) by the Pincher Creek Area Environmental Association (PCAEA). The claim for costs is in respect of applications by Shell Canada Limited (Shell) for licences to drill wells on Corner Mountain (Prairie Bluff) near Pincher Creek, which were considered by the Board at public hearings in August and September 1987.

The Board normally considers claims for awards of local interveners' costs through written submissions without oral argument. In this case the Board believed that because of the complex issues related to whether or not PCAEA is eligibile for costs, it was appropriate to consider the claim for costs at a hearing where verbal submissions could be presented.

Following completion of the "costs hearing" the Board delayed this decision until certain additional information was filed on behalf of PCAEA.

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives
(Abbreviations Used in Report)

Pincher Creek Area Environmental Association (PCAEA)
W. G. Geddes

Shell Canada Limited (Shell)
D. O. Sabey, Q.C.

Energy Resources Conservation Board staff
M. J. Bruni
J. K. Moloney

2 ISSUES

The Board believes that the issues are

(a) whether or not PCAEA qualifies as a local intervener, and

(b) if PCAEA qualifies as a local intervener, what costs should be awarded.

3 ELIGIBILITY FOR LOCAL INTERVENERS' COSTS

3.1 General

To make an award of costs pursuant to section 31 of the Act and the Local Interveners' Costs Regulation, the Board must determine that a claimant meets the test of section 31(1) of the Act, which is set out in detail in Decision D 83-8 as follows:

> "(A) Is the intervention in respect of land which is or may be, or which the use and enjoyment of is or may be, directly and adversely affected by a decision of the Board relating to the application under consideration, and
>
> (B) Does the person claiming costs
>
> (i) have an ownership interest in, or
>
> (ii) actually occupy or have a right to occupy in future,
>
> the land which may be directly and adversely affected?"

Decision D 83-8 goes on to say:

> "Even if a person is a "local intervener" for the recovery of costs, costs can only be awarded in respect of an application insofar as the application might affect the land or the use and enjoyment of the land for which there is concern. If an intervener chooses to pursue broad and general issues, he does so at the risk of his own expense. The Board believes it is explicit that costs can only be awarded for those portions of an intervention which deal with potential adverse affects on land or use and enjoyment of that land. The Board does not believe it has jurisdiction to impose a liability on an applicant otherwise."

3.2 Views of PCAEA

At the hearing of the well licence applications, PCAEA expressed concerns over emissions from the Waterton complex as well as sour gas operations in general. It presented as witnesses, local residents who related health problems they believed to be attributed to sour gas

operations. They suggested that the emissions and associated problems were at their worst during well testing.

Mr. Geddes, solicitor for PCAEA, stated that PCAEA is a group of 40 to 50 people who were concerned about possible harm to their own particular circumstances. He submitted it should not be necessary for those persons who live and farm their land in the area to decide in advance, on their own, whether the Shell operations on Corner Mountain as distinct from the Shell plant itself would likely be the cause of air pollution in the area. He also stated that without wells being drilled there would be no plant operations at all, and further, without new wells, the production from the plant would likely be decreasing and the air pollution in the area would likely decrease and the problems would decrease.

At the costs hearing, Mr. Geddes indicated that the well licence applications were for wells that were to be drilled on the top of Corner Mountain. Because of its height, the group anticipated that if a blowout or problem occurred in testing the wells, effluent starting from the higher level would travel farther. Mr. Geddes stated that any concentration of sulphur dioxide (SO_2) from the plant, and any concentration of hydrogen sulphide (H_2S) from a blowout of the wells or an operating problem with the wells, reaching members of PCAEA, would constitute a direct effect so as to qualify PCAEA for local interveners' costs. As well, any potential evacuation of members of PCAEA as a result of a blowout of one of the wells would also constitute a direct effect. Mr. Geddes agreed that a remoteness or a probability test should also be applied.

In answer to questions, Mr. Geddes indicated that the matter of the group qualifying for local interveners' costs was never discussed with the group. At the costs hearing, Mr. Geddes undertook to present the Board with a listing of members of PCAEA, together with their land descriptions, and an indication of those that were interviewed by Mr. Geddes in preparation for the interveners' submission at the hearing of the well licence applications.

3.3 Views of Shell

Shell stated that the participation of PCAEA was not relevant to the issues related to the well licence applications but pertained to the operations of the Shell Waterton gas plant. It further stated that no member of the PCAEA witness panel has an interest in, or is in actual occupation of, or is entitled to occupy, land that is or may be directly and adversely affected by the subject wells so as to qualify as a local intervener. Moreover, none of the PCAEA witnesses occupy land within the emergency planning zone. Although they may live in the Pincher Creek area, there is no evidence to suggest that lands in which they have an interest may be directly and adversely affected by any circumstances arising out of the drilling and production of the subject wells.

Shell stated that the essence of the PCAEA submission is that there will be more volume or longer periods of emissions from the plant operations, and that the impact of the wells was not defined at the well licence hearing and has not been defined by the costs application. Shell claimed that additional emissions from the plant resulting from the wells are a direct effect of the operation of the plant as distinct from the operation of the wells themselves, even though there is no question that there will be a greater total throughput at the plant. It said that since the Shell Waterton plant was not the subject of the proceedings, costs incurred in relation to examination of issues pertaining to the plant cannot be said to be directly and necessarily related to an intervention in these proceedings.

3.4 Views of the Board

During the costs hearing, Mr. Geddes undertook to provide the Board with a listing of PCAEA members, the location of their lands, and an indication of the people that he interviewed in preparation for the hearing. Later, Mr. Geddes filed additional information identifying the locations of nine of the members, and indicated that most of the people involved did not want to have their names publicized. On the basis of the additional information submitted, PCAEA has shown that its members own or occupy lands, and in intervening in the application for the well licences they showed a concern for the impact on the use and enjoyment of the land related to the Prairie Bluff wells. In order to qualify as a local intervener, PCAEA must also show that the use or enjoyment of the land its members own or occupy, and for which it has a concern, is land that is or may be directly and adversely affected by the Board's decision on the application for the well licences.

In this case, the Board believes that if there is a potential direct and adverse effect on the land of PCAEA, it would be from the wells and/or the plant; and these two will be discussed separately.

The Board has considered whether or not a potential direct and adverse effect could result from the plant as a result of the new wells being drilled and brought into production. The additional gas that would result from the drilling of the wells, according to Shell, is gas that would not otherwise be recovered and therefore additional total throughput to the plant would be achieved. This would result in an addition to total emissions from the plant. The Board is aware that the matter of plant throughput, operating characteristics, and emission levels was considered by the Board in late 1982 when Shell applied to the Board to process gas, which at that time was being processed by the Gulf Pincher Creek plant. The approval currently in place for the Shell Pincher Creek plant refers to gas produced from the Waterton, Pincher Creek, and Lookout Butte Fields, and includes throughput and emission levels approved by the Board. The Board notes from the evidence at the well licence hearing that the two wells are within the Waterton Field named in the approval, and that the plant is currently operating well within the approved throughput and emission limits and would continue to do so even with the additional gas produced from the two new wells.

The Board believes that for there to be a potential direct and adverse effect from the plant, a change to the plant's operating characteristics that had not previously been considered would have to occur. As this is not the case with respect to the two Prairie Bluff wells, the Board believes there is no potential direct effect from the plant on the interveners and therefore, PCAEA does not qualify as a local intervener with respect to the emissions from the plant.

The report will now discuss the claim for costs with respect to the potential impact from the wells themselves. The Board notes that PCAEA did not claim an impact would result on lands owned by the group from the drilling of the wells and construction of the access road. Rather, PCAEA expressed concern about well testing and the potential for a blowout. The Board also notes that according to the information supplied by PCAEA, none of the property owned or occupied by its members is located within the emergency planning zone for the wells.

In considering the potential impact of the wells and using the data provided by Shell at the well licence hearing, the Board has calculated the theoretical 10, 15, and 20 parts per million (ppm) H_2S isopleths, and has superimposed them on a map together with the location of PCAEA members' properties identified to the Board. The Board notes that two and possibly four members of the association fall within the calculated 20 ppm isopleth, and several others fall within the calculated 10 ppm isopleth. The Board is aware that the Guidelines for Action contained in the Alberta Government's Response Plan[1] discuss potential evacuation at H_2S levels of 1.0 ppm for sensitive persons and 20 ppm for others. Accordingly, if there were to be a blowout at either of the wells while drilling, or while operating after completion, the Board believes there is a possibility that H_2S gas could be encountered in quantities sufficient that evacuation would be considered.

Even though the potential for a blowout is small, the Board believes that members of PCAEA reside close enough to the well that in the unlikely event of a blowout, their evacuation could be contemplated. The Board believes that this constitutes a potential direct and adverse effect. Therefore, on the basis of the impact from the wells, the Board believes that PCAEA qualifies as a local intervener, and is prepared to award costs for its involvement related to the wells in the hearing of the well licence applications.

4 AWARD

In assessing the application for costs, and PCAEA's participation in the hearing, the Board notes that a considerable portion of the interveners' participation in the hearing was spent on matters related to emissions from the plant. The Board has determined that the association does not qualify as a local intervener for this participation, and therefore will not award all of the costs claimed. In reviewing the transcripts of the hearing of the well licence applications, and of the costs hearing, the

---

1 Government of Alberta Emergency Response Plan for a Sour Gas Release.

Board has concluded that more than one-half of the interveners' participation in the hearing related to the plant, as opposed to the wells. At the same time, the Board recognizes that by organizing its intervention at the hearing and limiting the attendance to a few witnesses, PCAEA enhanced the efficiency of the hearing.

The Board has denied the claim of $200.00 for preparing a submission because PCAEA did not actually file a written submission at the hearing. Instead, the Board has awarded $100.00 for the interveners' conferring with the solicitor prior to the hearing. The claim for expenses and for the interveners' attendance at the hearing is awarded as claimed.

With respect to the solicitor's fees, because PCAEA concentrated on the potential impact of the plant as opposed to the wells, and based on Mr. Geddes evidence that he spent 2 days prior to the hearing with the people in Pincher Creek, the Board is reducing this part of the claim by one half. It is therefore allowing 1 day or $937.50 for preparation for the hearing. With respect to the attendance at the hearing, the Board believes PCAEA needed to be at the hearing to properly be represented. The Board therefore has awarded fees for attendance as claimed. The amounts claimed for travel and disbursements are also awarded as claimed.

DETAILS OF THE CLAIM AND AWARD

	Claimed	Award
1. Intervener		
- Preparing submission	$ 200.00	$ 100.00
- Expenses	15.29	15.29
- Attending hearing	600.00	600.00
2. Solicitor		
- Preparation for the hearing	1 875.00	937.50
- Attendance at the hearing	3 375.00	3 375.00
- Travel	1 000.00	1 000.00
- Disbursements	292.11	292.11
	$7 357.40	$6 319.90

5 DECISION

1. PCAEA does not qualify as a local intervener with respect to potential impacts from the Shell Waterton gas plant.

2. PCAEA qualifies as a local intervener with respect to potential impacts from the Shell Prairie Bluff wells.

3. Costs for its participation in the hearing related to the wells are awarded to PCAEA in the amount of $6 319.90 and are to be paid by Shell Canada Limited.

DATED at Calgary, Alberta, on 27 March 1989.

ENERGY RESOURCES CONSERVATION BOARD

G. J. DeSorcy, P.Eng.
Chairman

F. J. Mink, P.Eng.
Board Member

J. P. Prince, Ph.D.
Board Member

E. J. Morin, P.Eng.
Board Member

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

CANADA NORTHWEST ENERGY LIMITED
APPLICATION FOR A WELL LICENCE
CAMPBELL-NAMAO FIELD

Decision D 89-6
Application 890471

1 INTRODUCTION

1.1 Application

Canada Northwest Energy Limited (CNW) applied, in accordance with section 2.020 of the Oil and Gas Conservation Regulations, for a licence to drill a well from a surface location in legal subdivision 5 of section 19, township 54, range 24, west of the 4th meridian, to a projected bottom-hole location in legal subdivision 10 of section 24, township 54, range 25, west of the 4th meridian. The proposed well, identified as CNW CAMAO 10-24-54-25, would be drilled to obtain production from the Basal Quartz sand.

1.2 Interventions

An intervention opposing the application was submitted by Mr. Nick Taylor, MLA for the constituency of Westlock-Sturgeon. Mr. Graeme MacKay appeared at the hearing to express concerns respecting the application. Mr. Hugh Crozier spoke at the hearing in support of the application.

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Canada Northwest Energy Limited (CNW) D. Edie	K. R. Bissett E. Saruk, P.Eng. H. Schoendorfer, P.Geol. M. Skinner W. Wolff, P.Eng.
N. Taylor, P.Geol.	
H. Crozier	
G. MacKay	
Energy Resources Conservation Board staff N. F. Lord, C.E.T. M. Semchuck, C.E.T.	

1.3 Hearing

A public hearing of the application was held on 4 May 1989 in Edmonton, Alberta, with Board Members G. J. DeSorcy, P.Eng., J. P. Prince, Ph.D., and Acting Board Member J. D. Dilay, P.Eng., sitting.

2 ISSUES

The Board considers the issues with respect to the application to be

- the need for and drilling of the well;
- the production of the well;
- sulphur recovery guidelines;
- administrative matters.

3 NEED FOR AND DRILLING OF THE WELL

3.1 Views of CNW

CNW submitted that the drilling of the proposed well could recover an additional 13 000 cubic metres of oil that may be left in place should the well be refused.

CNW stated that the well would also provide the geological information necessary for determining what, if any, additional drilling could take place in the area.

CNW submitted that it had initiated an extensive notification and public awareness program to inform all residents of the proposed well. CNW was not aware of any outstanding objections from local residents other than those tabled at the hearing.

Notwithstanding that few objections or concerns had been raised to the drilling of the well, CNW submitted that, as a prudent operator, it had prepared a very conservative drilling program and an exhaustive emergency response plan (ERP). These plans would, in CNW's opinion, more than adequately ensure that the well could be drilled safely with little or no inconvenience to residents. Further, in the unlikely event

of a mishap resulting in a release of hydrogen sulphide (H_2S), the ERP would ensure that CNW could more than adequately respond. This would be ensured by the detailed plan of responses to a mishap, given the low levels of H_2S expected to be encountered and correspondingly low potential release rate.

CNW stated that it was also prepared to implement mitigative measures such as noise abatement and the testing of water wells before and after drilling, to ensure no adverse effects to area residents.

3.2 Views of the Interveners

In general, the interveners did not question CNW's need for the well nor the adequacy of the drilling plan and ERP.

Both Mr. Taylor and Mr. MacKay stated they had no objection to the drilling of the well. Mr. MacKay submitted that his main concern was that no gas plant be constructed at the proposed well site. He also requested that all residents be given the opportunity to have their water wells tested, at CNW's expense.

Mr. Crozier, whose residence is near the proposed well, appeared at the hearing to support the application. Mr. Crozier submitted that existing facilities in the area had not had an adverse effect on himself or his property. In addition, he believed that as long as proper measures were undertaken to ensure that no environmental impact occurred, the Board should approve the well.

3.3 Views of the Board

The Board accepts CNW's submission with respect to the need for the proposed well. The Board believes, if the proposed well is successful, additional reserves could be recovered that may be inaccessible to existing facilities. Even if the well is not successful, the geological information obtained would be important in determining if further development is warranted in the area.

Having regard for the drilling plan and ERP, the Board believes the well could be drilled safely. However, given the possibility of encountering H_2S as well as the location of the well, the Board believes increased and detailed surveillance of all drilling activity is necessary. Therefore, if the well were approved, the Board would instruct its staff to make frequent inspections during the most critical phases of drilling. Also, the Board believes that the mitigative measures, such as noise abatement and the testing of residents' water wells, are appropriate. If, however, a dispute arose between CNW and an area resident as to implementation of a specific measure or the need to test a specific water well, this matter could be brought before the Board for further direction.

4 PRODUCTION OF THE WELL

4.1 Views of CNW

CNW submitted that the production of the well would not affect the surrounding region. If the well were successful, CNW proposed to pipeline all production to its existing battery and gas plant located in Lsd 13-12-54-25 W4M (13-12 plant). Regarding sulphur emissions at the plant, CNW said that even with the inclusion of production from the proposed 10-24 well, the plant's currently approved raw gas inlet rate, sulphur inlet, and emission rate would not be exceeded. Therefore, the total plant emissions would still be below the maximum level set for the plant, which is 0.28 tonnes per day (t/d) of sulphur equivalent.

CNW stated that it investigated the possible use of the Lo-Cat sulphur extraction process as proposed by Mr. Taylor. However, on the basis of economics and costs associated with the installation of sulphur removal technology, and the ability of current flare facilities to handle and emit the sulphur as sulphur dioxide and to comply with the current standards for ambient air quality, CNW stated it could not justify the installation of Lo-Cat sulphur removal equipment at its 13-12 plant.

4.2 Views of the Interveners

Mr. Taylor stated that his primary concern was with the production of the well going to the 13-12 facility and adding to the plant's present sulphur emissions. Mr. Taylor submitted that CNW should be required to install Lo-Cat sulphur extraction equipment at its 13-12 plant to make emissions negligible. Further, Mr. Taylor submitted that the installation of the Lo-Cat process would be appropriate for all plants in close proximity to large urban areas. In his opinion, the sulphur-removal requirements set by the ERCB and Alberta Environment are too low. Mr. Taylor also said that an unfair economic advantage was given to those companies not required to install sulphur removal facilities.

4.3 Views of the Board

The Board notes that, should the proposed well be successful, it would be produced to CNW's 13-12 plant. The primary objection tabled at the hearing relates to sulphur emissions at the plant.

The Board accepts CNW's evidence that the increased handling of production from the 10-24 well at the 13-12 plant should add only 0.003 t/d of sulphur equivalent to the existing plant's actual emission rate of 0.077 t/d, resulting in a likely maximum actual emission rate of 0.080 t/d. This is well below the plant's maximum approved sulphur emission rate of 0.28 t/d.

The Board notes that approval for the 13-12 plant's current maximum sulphur emission rate was granted in May 1987. That emission level was approved following a thorough review of the application, which included evidence from CNW of extensive communication with residents in the general area.

The Board believes that when the levels of emissions for a plant are considered and subsequently approved, follow-up wells consistent with the approved operating and emission levels are implicit in the plant approval. Given this, even though the possible impacts of each follow-up well must be considered before approval of the well licence, the Board does not believe that each such well should automatically result in reconsideration of the plant approval.

In this case, the Board does not see a need to review the approval of the 13-12 plant. It is satisfied that the very small additional emission, which would occur if the well is successful, would be acceptable. The concerns raised by Mr. Tayor respecting the sulphur recovery guidelines are discussed further in the next section of this report.

5 SULPHUR RECOVERY GUIDELINES

5.1 Views of the Board

The Board notes Mr. Taylor's claim that an unfair economic advantage is being given to gas processing plant owners who are not required to install sulphur removal facilities. The Board believes Mr. Taylor's position may be the result of some misunderstanding of the sulphur recovery requirements. The two processing schemes that Mr. Taylor made reference to regarding his concern are:

Plant Operator	Plant Location (W4M)	Raw Gas Throughput (10^3 m^3/d)	Daily Maximum Approved Sulphur Inlet Rate (t/d)	Daily Maximum Approved Sulphur Emission Rate (t/d)
Norcen (proposed)	5-1-55-25	1 583.0	1.15	0
CNW	13-12-54-25	564.0	0.28	0.28

Mr. Taylor implied that the "unfairness" has been brought about by the Board's new sulphur recovery guidelines (IL 88-13). The guidelines now require new plants, with a maximum daily sulphur inlet rate of 1.0 t/d or more, to utilize sulphur removal facilities. The guidelines stipulate that 50 per cent of the increased cost burden of sulphur recovery, for new plants at 1.0 to 5.0 t/d, would be carried by the public sector by reducing the plant owner's royalty liability.

Norcen's proposed facility falls within the sulphur removal requirement category (greater than 1.0 t/d) and the CNW plant is well below that cut off. The 13-12 plant's present sulphur inlet rate was approved by the Board in May 1987, well in advance of IL 88-13. In his written intervention, Mr. Taylor was implying that, if the CNW plant was being considered by the Board today, with the new guidelines, sulphur removal would be required. This would not necessarily be so, because the inlet rate is well below 1.0 t/d.

The Board recognizes that when new requirements are imposed for new facilities without some retroactivity for existing facilities, it may be perceived that some inequity may result in favour of the existing facilities. It also recognizes that when new requirements are imposed retroactively on existing facilities, the extra costs associated with retrofitting can be seen as an inequity against existing facilities. In the case of the recently changed sulphur recovery guidelines, the Board and Alberta Environment concluded that there were no significant negative impacts being caused by emissions at facilities approved in accordance with the old guidelines. This, coupled with the view that there would be no substantial advantage for any existing plant owner or producer whose reserves may be processed at a plant not affected by the new guidelines, resulted in their not being made retroactive. However, if it was demonstrated that inequities were occurring and having a negative impact on the public interest, the Board would give further consideration to such situations on a case-by-case basis.

Mr. Taylor's major concern relates to the current sulphur recovery guidelines, which in his opinion are not severe enough for facilities situated near urban areas. The Board notes that these guidelines were established following an extensive review process. The process, which was initiated by a Task Force Report in late 1986, also involved the sour gas processing industry as well as representatives of special interest groups and members of the broad public.

The review led to a strengthening of the standards set for emissions. Of particular interest in terms of the CNW application, the minimum plant size for which sulphur recovery is required was reduced from 10 t/d to 1.0 t/d. In this respect, the standards are among the most stringent requirements in North America. These tougher requirements were imposed even though there is no evidence available which demonstrates that negative impacts have resulted from such small emissions occurring in a manner that meets the stringent ground-level standards.

The Board notes that the CNW 13-12 plant's current emission rate was approved in 1987. Furthermore, its approved emission rate is less than one-third that of the new minimum sulphur recovery requirement for plants with sulphur inlet rates of more than 1.0 t/d. The plant's actual emission rate expected by CNW, including the applied-for well, is expected to be less than one-tenth of the minimum size at which sulphur recovery would be required.

The ERCB and Alberta Environment periodically review the sulphur recovery guidelines. Moreover, if a site-specific need is established, the Board can impose more stringent sulphur recovery requirements for specific plants than those set out in the guidelines. Given that the sulphur recovery guidelines have recently been reviewed, the Board does not see a need at this time to revise the guidelines.

6 ADMINISTRATIVE MATTERS

6.1 Views of the Interveners

Both Mr. Taylor and Mr. MacKay requested that the Board attempt to hold public hearings in close proximity to the area where a project is proposed. They suggested that the hearings should also be held at a time, preferably in the evening, when more interested parties could attend.

Mr. Taylor stated that in this specific case, the City of Edmonton (City) should have been given direct notice of the hearing by the Board.

6.2 Views of the Board

With respect to the Board's procedure in holding hearings, the Board tries in each case to hold hearings in locations convenient for all interested parties, particularly those living in the vicinity of a proposed project. This must be done bearing in mind the requirements for appropriate hearing facilities, the schedules of involved parties, and the Board's schedule. Regarding sitting hours, the Board is receptive to holding at least portions of a hearing in the evening to accommodate interested parties if such a request is submitted prior to the hearing being convened.

As to the notification procedures for this particular hearing, the Board acknowledges this as a valid concern. The Board's practice, as set out in Interim Directive ID 88-2, is to provide direct notice to rural and urban administrations located within 1.5 kilometres of a proposed well. The Board believes this distance to be a reasonable limit for provision of direct notice particularly when, as in this case, notice of the hearing appears in the major and local newspapers. Moreover, in the matter at hand, the Edmonton Metropolitan Regional Planning Commission did receive notice and the City is represented on the Commission. If a submission had been received on behalf of the City it would, of course, have been considered at the subject hearing.

7 DECISION

The Board has carefully considered all the evidence, including the concerns of the interveners and the submission of the applicant. The Board has determined that the well could be drilled safely and with minimal impact on surrounding residents. The Board believes that should

the well prove productive, the 13-12 plant's emissions would not increase to a level exceeding its currently licensed sulphur emission rate or the limits set by current regulations and provincial air quality standards.

Accordingly, the application is approved and a well licence will be issued in due course.

DATED at Calgary, Alberta, on 11 July 1989.

ENERGY RESOURCES CONSERVATION BOARD

G. J. DeSorcy, P.Eng.
Chairman

J. P. Prince, Ph.D.
Board Member

J. D. Dilay, P.Eng.
Acting Board Member

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

UNOCAL CANADA MANAGEMENT LIMITED
APPLICATION FOR APPROVAL OF A
SWEET GAS PROCESSING PLANT
ALBRIGHT AND BEAVERLODGE FIELDS

Decision D 89-7
Application 880830

1 INTRODUCTION

1.1 The Application

Unocal Canada Management Limited (Unocal) applied, pursuant to section 26 of the Oil and Gas Conservation Act, for approval to construct and operate a sweet gas processing plant at an existing well site located in legal subdivision 6, section 17, township 72, range 9, west of the 6th meridian (6-17), in the Albright Field. The plant would be designed to process a maximum of 300.0 thousand cubic metres per day (300.0 x 10^3 m^3/d) of raw gas from which 297.4 x 10^3 m^3/d of sales gas and 7.8 m^3/d of liquefied petroleum gases (LPG mix) would be recovered. No sulphur or sulphur compounds would be emitted to the atmosphere.

1.2 The Hearing

In its 20 March 1989 Notice of Hearing, the Board indicated that it would consider the Unocal plant application in conjunction with applications by Dome Petroleum Limited (Dome) to gather and transport raw gas from the Albright and Beaverlodge fields to its existing Sinclair gas processing plant (Sinclair plant) located in the southwest quarter-19-72-11 W6M. The Unocal and Dome applications represented a scheme to divide production from three joint-interest wells and produce them to both the Sinclair gas plant and the proposed Albright gas plant by way of a flow splitter.

However, by letter dated 14 April 1989, Amoco Canada Petroleum Company Ltd. (Amoco) (on behalf of Dome) indicated that it had revised its capital spending strategy and requested that its applications be deferred for a period of 6 to 8 months. Amoco also indicated that it did not oppose Unocal's application and would not participate in the 24 April 1989 hearing.

Consequently, Application 880830 was considered at a public hearing in Grande Prairie, Alberta, on 24 to 26 April 1989, with F. J. Mink, P.Eng. (Chairman), E. J. Morin, P.Eng. (Board Member), and E. G. Fox, P.Eng. (Acting Board Member), sitting. Those who appeared at the hearing are listed in the following table.

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Unocal Canada Management Limited (Unocal) S. Wright	F. H. Perschon, Jr., P.Eng. S. Leson, P.Eng. N. C. Kelly, P.Eng. all of Unocal J. A. Lore, P.Ag. of Jim Lore & Associates D. E. Reid, P.Biol. of Hardy BBT Limited
Local Interveners J. D. Carter	Ken Evans Ray and Rhoda D'Aoust Drs. Nigel and Daphne Fairey David White
Allen Lowe	Allen Lowe
Energy Resources Conservation Board staff C.J.C. Page C. L. McAdie, R.E.T. L. S. Fillion, R.E.T.	

1.3 Preliminary Matters

As a result of Amoco's request for deferral of its applications, Mr. Carter, on behalf of the interveners, requested that the Board defer consideration of the Unocal application. Mr. Carter suggested that since Amoco had requested that its applications be deferred rather than withdrawn, it was likely that Amoco would ultimately proceed with its plan to transport its share of the Beaverlodge reserves to the Sinclair plant. Mr. Carter argued that consideration of the Unocal and Amoco applications separately would effectively prevent the Board from determining the most economic, orderly, and efficient scheme for development of the Beaverlodge reserves. In addition, Mr. Carter contended that a thorough evaluation of the Sinclair processing alternative could not be pursued without input from Amoco, the plant operator.

Unocal argued that there was no guarantee that Amoco would proceed with its applications, and pointed out that Amoco did not oppose the 6-17 plant application. Furthermore, Unocal stated that the interveners' grounds for opposing the 6-17 plant, namely, detrimental effect on life-style, reduced property values, processing alternatives, and life of the plant, were unaffected by Amoco's deferral of its application.

Conversely, Unocal argued that deferral of its application would prevent it from meeting its contractual obligations. In conclusion, Unocal stated that its application was complete, and that it had a right to have its application heard, and requested that the hearing proceed.

The Board considered the arguments made by the interveners and the applicant and agreed that the interveners' concerns respecting processing alternatives warranted careful consideration, but noted that Unocal had filed an application that spoke to those concerns and was prepared to elaborate on the issues. Therefore, the Board decided to proceed with the hearing.

During the course of the hearing, the Board and interveners visited the proposed plant location and viewed the residential development in the area surrounding the site.

2 ISSUES

The Board considers the issues to be

- need for processing facilities,
- processing alternatives, and
- impacts and relative desirability of the proposal and any processing alternatives.

3 NEED FOR PROCESSING FACILITIES

3.1 Views of Unocal

Unocal indicated that it was a joint owner with Amoco of four existing wells and had acquired an interest in some 36 sections of undrilled land in the Beaverlodge area. The applicant also indicated that its share of the Beaverlodge reserves had been dedicated to a long-term export sales contract with a customer in eastern Canada. Unocal pointed out that its contract had taken effect on 1 November 1988 and since that time, Unocal had been forced to purchase gas in order to meet its commitments. Consequently, the applicant maintained that it was imperative that the Beaverlodge reserves be brought on stream as quickly as possible.

With respect to the options available for processing, Unocal indicated that it had investigated the feasibility of utilizing four existing plants. Each of these alternatives was considered unacceptable to Unocal for various reasons. These include: the nearest alternative plant site is about 13 km from the reserves, there is inadequate

processing capacity, and firm transportation from the plants on the NOVA system is not available. On that basis, Unocal concluded that there was no viable processing alternative and that a new scheme was required.

Regarding the interveners' suggestion that its application be considered with the Amoco applications at a future date, Unocal stressed that it had invested capital and acquired a sales gas contract to which the Beaverlodge reserves were dedicated. Unocal contended that Amoco's corporate spending strategy should not dictate Unocal's investment opportunities.

3.2 Views of the Interveners

The interveners recognized Unocal's investment in the area and did not question the applicant's right to produce its reserves. However, the interveners argued that development of those reserves should proceed in an economic and environmentally and socially acceptable manner.

3.3 Views of the Board

The Board accepts that the applicant has a right to produce its reserves and to have reasonable access to a market. In order to do so, the applicant must have access to gas processing facilities. However, it is the Board's mandate to ensure that energy development, deemed to be in the public interest, proceeds in an economic, orderly, and efficient manner. Therefore, the relative merits of the proposed scheme as compared with other processing alternatives must be considered.

4 PROCESSING ALTERNATIVES

4.1 Views of Unocal

Unocal indicated that it had investigated the feasibility of utilizing existing gas processing facilities in the area, namely, the Dome-Wembley, Total-Knopcik, Canadian Hunter-Elmworth, and Dome-Sinclair gas plants. Unocal pointed out that none of the existing plants currently has approval to process gas from the Albright and Beaverlodge fields and, in each case, that gas would have to be pipelined a considerable distance (13 km or more) in order to be processed.

With respect to existing plant capacity, Unocal stated that both the Dome-Wembley and Total-Knopcik plants would have to be expanded in order to accommodate Unocal's gas reserves. Processing capacity was only available on a "best-efforts" basis at the Canadian Hunter-Elmworth plant, and Unocal claimed that modifications to the Dome-Sinclair plant would be necessary in order to obtain the required processing capacity on a continuous basis.

Regarding the availability of NOVA transportation out of an existing facility, Unocal stated that the Total-Knopcik plant could possibly supply firm transportation since it would deliver gas into the same portion of the NOVA system as the proposed 6-17 plant, once NOVA's Huallen pipeline is constructed. Firm transportation is not available from the Elmworth or Wembley plants. Unocal suggested that firm transportation out of the Sinclair plant was subject to expansion of the NOVA system downstream of Sinclair, and would require certain concessions on the part of both Amoco and NOVA.

Unocal added that of the alternatives considered, only the Sinclair option merited serious consideration in that Amoco was both the plant operator and a 50-per-cent-owner of the Beaverlodge gas production. However, following 2 years of negotiations with Dome and subsequently Amoco, Unocal's concerns respecting the availability of plant capacity, firm transportation, process fees, and timing, had not been resolved to its satisfaction.

Unocal indicated that in general it supported the Board's desire to utilize existing plant capacity where possible and to prevent a proliferation of gas plants. However, the applicant stated that utilization of existing facilities should not be required at "all costs", but rather where it is economic, orderly, and efficient to do so. Furthermore, when asked under what circumstances it would consider utilizing existing processing facilities, Unocal suggested that the business opportunity of such a scheme would have to at least equal that of a new scheme.

The applicant maintained that it had explored all of the opportunities available to it. However, in this case, since there was no existing plant capacity, no available firm transportation, and no economically acceptable alternatives, Unocal claimed that the issue of proliferation did not apply and the construction of a new plant was justified.

4.2 Views of the Interveners

The interveners suggested that in evaluating the processing alternatives, consideration should be given first to all other existing facilities that could be expanded or modified in some way to accommodate the additional gas reserves. It was their opinion that attempting to locate a suitable existing plant should precede any consideration of new plant sites in an effort to avoid a proliferation of plants.

The interveners did not accept Unocal's proposition that existing plants should be utilized only if the costs were equal to or less than that of a new plant. Rather, the interveners interpreted the Board's policy to mean that within reason, existing plants should be utilized even if it were a little more costly to do so. The interveners concluded that economics should not be the deciding factor but that due regard must be given to the social implications of any energy development.

In determining an appropriate location for a new plant, the interveners stated that in addition to the economic and engineering details, consideration must be given to the environmental and social impacts on an area. Specifically, the interveners suggested that every effort should be made to minimize disruption to the environment and to individuals by avoiding locations in proximity to residences.

Furthermore, the interveners stated that a review of the economics submitted by Unocal indicated that the construction of a pipeline to transport all of the Albright/Beaverlodge gas to the Sinclair gas plant is at least as economic, if not more economic, than building a new gas plant.

The interveners indicated that the Dome-Sinclair gas plant was the processing alternative preferred by them and processing Unocal's gas at that facility would be consistent with the Board's policy on plant proliferation.

4.3 Views of the Board

The Board believes a key element when investigating alternative processing options is the full consideration of using existing facilities. This would include consideration of spare or expanded capacity at existing sites. In doing so the merits of existing facilities can be considered in contrast to building a new plant.

In this instance, the Board notes that use of four existing plants was investigated and rejected by the applicant. Grounds for rejection were that some could not accommodate the new gas without expansion, did not offer firm capacity on a continuous basis, could not offer firm transportation on the NOVA system, and/or were less economically attractive than the development of a new site. Only the Dome-Sinclair plant was considered a viable existing option and it was the focus of analysis in comparing the merits of alternative processing schemes.

The Board accepts the position of Unocal that Dome-Sinclair offers the best opportunity for processing its gas at an existing facility. However, the Board cannot accept the position of Unocal that the Sinclair plant is not a viable option since it cannot provide firm capacity and presents a pipeline restriction on the NOVA system. From the evidence submitted, the Board concludes that Amoco is prepared to offer firm processing capacity with equity participation and sharing of firm transportation arrangements on the NOVA system at the proposed level of production. While the Board acknowledges that those arrangements are subject to some agreements with other owners of the Sinclair plant and some discussion with NOVA, the Board cannot conclude from the evidence that those undertakings would not be met. Given that Amoco is the operator of the Sinclair plant and majority owner, the Board takes Amoco's statement offering firm capacity as a serious

commitment to provide that opportunity. The Board also understands that NOVA's policies do not categorically prevent the re-assignment of firm transportation capacity on its system. Considering that Amoco has agreed to re-assign equivalent firm transportation capacity on the line delivering gas from the Sinclair plant, the Board concludes that adequate capacity could be available to deliver the Unocal gas. In the long term, Unocal could make its own arrangements for capacity on the NOVA system.

Finally, the Board also notes Unocal's argument that the delivery and processing of gas to the Sinclair plant is less economic than the construction of a new plant at Albright. However, the Board must consider the disadvantage of reduced economics against the other impacts associated with a new site.

While the Board's policy generally is to discourage the proliferation of gas processing facilities, it does not intend doing so at all costs. Two of the more important considerations are economic factors and the impact of alternatives.

In this instance, Unocal's own economic analysis confirms that a new gas plant at Beaverlodge or a pipeline to the Dome-Sinclair plant are nearly equal, acceptable alternatives. A new gas plant at Beaverlodge is economically more attractive only if significantly increased plant throughput is assumed. Since such an increase is not supported by the application, it need not be considered further.

The Board therefore concludes that use of an existing plant is a legitimate option that should be pursued further.

5 IMPACTS AND RELATIVE DESIRABILITY OF THE PROPOSAL AND ANY PROCESSING ALTERNATIVES

5.1 New Plant in Beaverlodge Area

5.1.1 Views of Unocal

Unocal indicated that it had a contract to supply 141 x 10^3 m^3/d of gas with opportunity to market up to 197 x 10^3 m^3/d on occasion. Considering the development potential for the area, the interest expressed by other area producers, and the marginal incremental costs, Unocal had made provision for possible future increases in production in applying for a plant with a capacity of 300 x 10^3 m^3/d. In addition, Unocal advised that it had acquired firm transportation in NOVA's proposed Huallen lateral. Consequently, Unocal considered the construction of a new plant to be superior to utilizing an existing facility since it would allow Unocal to retain operatorship of the scheme while providing adequate capacity and transportation to meet its immediate and future requirements.

With respect to the siting of a new plant in the Beaverlodge area, Unocal indicated that its initial selection criteria had considered proximity to the producing wells, access to the site, and topographic features. On that basis, two possible sites were identified, namely, Lsd 6-17-72-9 W6M and the NW 1/4-18-72-9 W6M (NW 1/4-18). Then, based on population density, the visibility of the site, economics, and potential environmental impacts, Unocal chose the 6-17 site as its preferred plant location. The site in NW 1/4-18 received only a cursory review.

After acquiring a lease from the surface landowners, Mr. and Mrs. A. Lowe, Unocal undertook to advise area residents of its gas processing scheme. Initial contact was made in June 1988 when Unocal delivered a public information brochure to area residents within a 1.6-km radius of the 6-17 site. Unocal explained that the concerns of area residents were then addressed in a series of newsletters, personal visits, telephone calls, and letters. At a public meeting conducted by Unocal in Beaverlodge in October 1988, residents again raised concerns respecting matters of the environment, land values, traffic, and quality of life. In response to those concerns, the applicant retained consultants to undertake a study of the potential environmental impacts of its proposed plant, as well as to provide advice respecting the effect of gas production facilities on land value.

Regarding the issue of decreased land values, Unocal concluded that although certain purchasers may be influenced by the presence of oil or gas production facilities, such facilities have no appreciable impact on market value. The applicant indicated that it had reached its conclusions based on a study of the effect of sour gas production facilities on land values in the Sundre area. Unocal postulated that if sour gas production facilities could not be shown to have a statistically significant impact on market values, then sweet facilities would likely have even less impact since there was less risk to the public associated with sweet facilities.

Regarding the impact of a sweet gas plant on the wildlife population in the area, the environmental report concluded that temporary disturbances would be likely during the construction of the plant; however, the overall effect on the animals in the area would be minimal. Although it had not undertaken to observe wildlife movements in the specific area, Unocal stated that research done by others suggested that wildlife is relatively tolerant of oil and gas production operations and would grow accustomed to the uniform noise associated with normal plant operations. Furthermore, since no forested land would have to be cleared in order to utilize the 6-17 site, Unocal speculated that wildlife movements would not be affected in the forested area immediately adjacent to the north boundary of the plant site. In addition, Unocal submitted a letter dated 31 October 1988 from B. Wynes, an official from the local Forestry, Lands and Wildlife Division. Based on his review of an alignment sheet of the plant, the official stated that he did not anticipate that there would be any major impact on wildlife in the area as a result of the proposed 6-17 plant.

In an attempt to mitigate the residents' other concerns, Unocal committed to augment the existing tree cover by planting rows of trees at the perimeter of the site to reduce visibility and noise impacts. In addition, Unocal committed to further reduce noise impacts by placing the compressor engines in insulated buildings, fitting the exhaust stacks with mufflers, and utilizing low-speed fans equipped with accoustically insulated shrouds.

Unocal had also committed to cover its proportionate share of any road upgrading or dust control measures deemed necessary by the County of Grande Prairie. However, Unocal indicated that the County was not presently considering an upgrade of the gravel road which provides access to the 6-17 site and the Spring Hill Estates subdivision where most of the interveners reside.

Unocal submitted that it had made every reasonable effort to resolve the residents' concerns; however, certain individuals remained opposed to the scheme. Unocal suggested that the remaining concerns could not be alleviated unless the scheme were relocated to some other site.

The applicant concluded that its proposed scheme was technically and environmentally sound and was designed to meet all safety and conservation regulations, and that because no reasonable processing alternative exists, Application 880830 should be approved.

5.1.2 Views of the Interveners

The interveners maintained that if for some reason an existing plant could not be utilized, Unocal had not adequately considered possible alternative sites for its proposed plant.

All of the local interveners who appeared at this hearing indicated that they originally chose to live in the area around the proposed 6-17 location because of the unique, secluded nature of the region. They stated that they believed that the construction of a gas plant in this area could be detrimental to the quality of the life-style that they presently enjoyed.

The interveners pointed out that there were a number of residences in close proximity to the proposed plant site, including a residential subdivision called Spring Hill Estates located approximately 1.0 km to the east. The interveners were concerned that the construction of a gas plant in the middle of a densely populated area such as this would result in a conflict of land use, and a reduction in the economic and aesthetic value of the surrounding residential properties. Mr. R. D'Aoust, the developer of Spring Hill Estates, claimed that the proposal to construct a gas plant at the 6-17 location has affected the potential sale of acreages in his subdivision. Mr. D'Aoust indicated that the sale of two or three of his acreages had been deferred pending the results of this hearing.

The interveners had two major concerns about the fact that the proposed gas plant would be located in one of the lowest areas of the region with respect to elevation. The interveners stated that this area has a high water table and they were concerned that surface runoff and chemical spills at the plant could have an effect on the quality of the water used by the surrounding area residents. They also had concerns regarding the impact that building the plant at the 6-17 location would have on the noise levels that would emanate from the facility. The interveners stated that the valley is shaped like a bowl, with the proposed plant site located at the lowest spot, and they claimed that this would result in the noise from the plant being echoed throughout the valley. The local interveners supported that claim by stating that even at the present time, noise from as far away as the community of Beaverlodge, approximately 5 km to the southwest, can be heard by residents who live in the vicinity of the proposed plant site.

The interveners stated that there is an abundance of wildlife in the region which they believe could be affected by the construction of a gas plant at the 6-17 location. The interveners stated that moose and other wildlife move down from Saskatoon Mountain through a corridor which runs to the immediate north of the proposed plant site. The interveners maintained that because detailed observations of the movement of wildlife in this region have not been conducted, a conclusion stating that the proposed plant would have a minimal impact on area wildlife is not justified. Furthermore, one of the interveners, K. Evans, stated that he had discussed this specific matter with B. Wynes of Alberta Forestry, Lands and Wildlife, the same contact with whom D. Reid of Hardy BBT Limited had spoken. K. Evans stated that he concluded from his conversation with B. Wynes, however, that the department does not have a true understanding of the extent of the wildlife activity in the vicinity of Saskatoon Mountain and therefore, the letter dated 31 October 1988 from Alberta Forestry, Lands and Wildlife to D. Reid should be given little weight when assessing the potential impact of the proposed plant.

The interveners are also concerned that the existing access road which runs east from Highway 723 to the 6-17 location is inadequate to handle the truck traffic which would be associated with the construction and operation of the proposed gas plant. The interveners stated that the road is narrow and has steep ditches on either side; the result is that the road is difficult to travel at the present time, especially when it is wet. The interveners are concerned that heavy truck traffic could cause deterioration of the road and restrict the use of this access road by the area residents.

The interveners also stated that they had concerns that if a facility of the type being proposed is approved in this area, expansion and the potential to process sour gas at this plant could easily follow. The interveners noted that the applicant alluded to plant expansion in a

number of its submissions, and further noted that the gas gathering system to move gas from these facilities was designed by Dome to meet sour specifications.

Finally, the interveners submitted that they were not given the opportunity to provide any input prior to the selection of a gas plant site and that there was inadequate consideration given by the applicant to alternative locations for its proposed plant. The only alternative site which was apparently given any consideration by Unocal, NW 1/4-18, is opposed by the interveners for many of the same reasons that they oppose the proposed 6-17 plant site. The interveners maintain that the impacts of constructing a plant at the NW 1/4-18 location would only result in a transfer of the impacts of a gas plant onto other area residents, rather than an elimination of those impacts.

The interveners stated that if it were determined that a new gas processing plant was required in the Albright/Beaverlodge area, then it should be located at a site removed from any area residents. The interveners suggested that a site in section 29-72-9 W6M should be investigated, a site which they indicated was on Crown land with no residents in the vicinity.

The interveners also stated that they had no objections to the impact that may be caused by a new pipeline that would remove the gas produced from the area.

5.1.3 Views of the Board

The Board believes that the topography and sheltered terrain surrounding Saskatoon Mountain is unique to the area, and accepts that special measures should be taken to avoid land-use conflicts between residential and industrial users. At the same time the Board believes public demands for land-use priority must recognize the right and opportunity for development of energy resources in the area in an orderly and efficient manner.

Contrary to the views expressed by the applicant in this instance, the Board believes the proposed facility would have a greater and more permanent impact on noise, traffic, and wildlife in the area than portrayed. Given the setting, the Board believes these and other impacts should be imposed only if other available sites are intruding to the same degree or offer other unacceptable impacts. The Board is satisfied that wildlife frequents the area of the 6-17 site and gradual expansion of industrial activity at the location would have more than short-term effect.

The Board accepts the submission by Unocal that the proposed plant would not affect the local water quality or supply.

With a large portion of the province's economic base dependent on the oil and gas industry, good relations between that industry and the public are essential. In that regard, the Board believes that proper public consultation is a critical component to site selection for new facilities and measures should be taken so that the public's concerns are considered and respected and any potential impact is minimized. As part of this consultation, the proponent should seek the input of the area residents in the determination of a suitable location for the scheme. This could involve the identification of a number of possible sites for the proposed scheme and only after consideration of the needs and requirements of both parties should a potential site be selected.

The Board recognizes, however, that a satisfactory resolution to the selection of a site for a scheme may not be achieved, and a public hearing may be the only way of resolving a confrontation between the scheme's proponent and the area residents.

In this particular case, there is no evidence to show that a thorough review of alternative sites that had a serious potential for resolving land-use conflicts was conducted by the applicant. It is noted that the proposed 6-17 location does appear to meet Unocal's requirements for the processing of its share of the gas produced in the Albright and Beaverlodge fields. However, it also appears that Unocal selected the 6-17 site for its proposed plant based almost entirely on its own priorities, and then attempted to mitigate the concerns that the area residents had about this site when they subsequently arose, rather than attempting to select a site which would fulfil its requirements and alleviate the residents' concerns.

It is further noted that the applicant's environmental consultant did identify the NW 1/4-18 site as an alternative location for the proposed plant. Again, however, there is no evidence to suggest that this alternative site was given serious consideration by Unocal and it appears that the applicant attempted to discredit this site rather than investigate seriously the feasibility of relocating the plant.

The Board is not satisfied at this time that the 6-17 site represents the only suitable location for Unocal's proposed gas plant. If it is determined that a new plant in the Albright/Beaverlodge area is required in order to process Unocal's gas, the Board believes that further investigation of other potential locations in this region is warranted. Furthermore, the Board believes that if Unocal had consulted the area residents with regard to the selection of an appropriate location for the proposed plant, and had thoroughly investigated the feasibility of utilizing these alternative locations during the application process, there is a possibility that this hearing could have been avoided.

5.2 Dome-Sinclair Processing Alternative

5.2.1 Views of Unocal

Unocal stated that it had discussed with Dome, and subsequently Amoco, the feasibility of processing Unocal's share of the gas produced in the Albright and Beaverlodge fields at the Dome-Sinclair gas plant. In its letter to the Board dated 14 April 1989, Amoco indicated that it was prepared to offer Unocal 141 x 10^3 m^3/d of firm processing capacity at the Dome-Sinclair gas plant and a re-assignment to Unocal of an equivalent amount of firm transportation on the NOVA system from Dome's plant.

Unocal, however, stated that it had rejected Amoco's offer for the following reasons:

- The offer of firm processing capacity in the Sinclair gas plant is subject to the approval of the other plant owners. At the time of the hearing, Unocal had not investigated whether or not the other plant owners were prepared to provide processing capacity. However, Unocal indicated that it did not believe that there is sufficient spare capacity at the Sinclair gas plant to accommodate Unocal's gas volumes at the present time without installing a screw compressor at the plant. Unocal stated that it believed that the Sinclair gas plant could effectively process a maximum of approximately 1400 to 1500 x 10^3 m^3/d of raw gas, and 1247 x 10^3 m^3/d of that volume is dedicated to Amoco's existing TCPL contract. Unocal maintained that the remainder, approximately 153 x 10^3 m^3/d of processing capacity, is insufficient to accommodate both Unocal's and Amoco's share of the gas which will be produced from the Albright and Beaverlodge fields.

  Furthermore, Unocal stated that it did not believe that any of the other plant owners would give up any portion of their share of the processing capacity at the Sinclair plant and, therefore, did not believe that Amoco would be able to obtain the necessary partner approval to provide Unocal with the processing capacity it requires.

- Unocal stated that it has obtained a total of 282 x 10^3 m^3/d of firm transportation capacity from its proposed 6-17 plant site in the proposed NOVA Huallen pipeline lateral with a tentative in-service date of 1 November 1989. This capacity consists of the 141 x 10^3 m^3/d of transportation which is required to deliver gas to Unocal's export market (T-5 service) and an additional 141 x 10^3 m^3/d of transportation for delivery to markets within the province of Alberta (T-1 service).

  Unocal further stated that there is no firm transportation from the Dome-Sinclair gas plant available to Unocal at the present time. Amoco stated in a letter to Unocal dated 7 February 1989 that Dome

had obtained a service agreement with NOVA for 141 x 10^3 m^3/d of firm transportation from the Sinclair plant to tentatively commence 1 November 1989, which it was prepared to assign to Unocal. However, this proposal to assign 141 x 10^3 m^3/d of NOVA transportation from Amoco to Unocal is subject to two conditions which Unocal stated were unacceptable: the offer is subject to approval by NOVA, and there is no guarantee that the transportation would be available by 1 November 1989.

With regard to the former, Unocal stated that there are two components to an approval by NOVA of the transportation assignment: the actual approval of the transfer of the service agreement from Amoco to Unocal, and approval to change the type of transportation from T-1 service to T-5 service. Unocal further stated that it did not know for certain if NOVA would agree to make the appropriate changes in its service agreement with Amoco to provide Unocal with the transportation it requires to deliver its share of the Albright/Beaverlodge gas to its export market from the Dome-Sinclair gas plant.

Unocal also stated that although NOVA's service agreement with Amoco indicated that the requested transportation from the Sinclair gas plant could become available by 1 November 1989, this date is tentative and dependent on NOVA completing construction aimed at removing a restriction on its system downstream of the Sinclair plant. Unocal stated that because Amoco would not, or could not, provide a guarantee that NOVA transportation from the Sinclair gas plant would be available by 1 November 1989, there is no assurance that deliveries of gas to Unocal's export market could commence by that date and therefore, Unocal could not accept the offer of the transportation assignment.

Unocal also stated that it preferred to construct its own plant in the Albright/Beaverlodge area because that would allow it to have control of the development of its established and potential reserves in this area. The applicant further stated that when these reserves are eventually depleted, the processing equipment can be moved from the proposed 6-17 site and used to process gas in another area of the province, whereas a pipeline to the Dome-Sinclair plant would have to be abandoned in place. Unocal stated that this would result in the loss of facilities and the inherent salvage value of those facilities. Therefore, Unocal indicated that it believed that this factor, combined with the capital cost component of installing the previously mentioned screw compressor at Dome's plant, meant that processing its gas in the Sinclair plant represented a less efficient and less economic processing alternative.

5.2.2 Views of the Interveners

The local interveners stated that because the ownership of the gas to be processed in the proposed Unocal plant is split equally between Unocal and Amoco, and because Amoco has applied to transport its share of this gas to the Sinclair plant for processing, the utilization of the existing Dome-Sinclair plant to process this gas is the most practical and appropriate alternative.

The interveners noted that Amoco's applications to transport its portion of the Albright/Beaverlodge gas to the Sinclair gas plant have been deferred, not withdrawn, and that Amoco had indicated in its letter to the Board dated 14 April 1989 that it may proceed with its applications in approximately 6 to 8 months. The residents stated that the Sinclair alternative would preclude the construction of additional surface facilities in the Albright/Beaverlodge area and subsequently, the noise and visual impacts that would result from the construction and operation of a new plant in the area would be prevented. Proceeding with this alternative would also minimize the potential impact on area wildlife.

Therefore, the interveners maintained that the alternative of transporting the Albright/Beaverlodge gas to the Dome-Sinclair gas plant would satisfy the processing requirements of both Amoco and Unocal in an economic and efficient manner, and would alleviate the concerns of the area residents. They further maintained that this alternative would represent a unified scheme which would allow both Unocal and Amoco to develop their reserves in this area without jeopardizing the unique nature of the region, and would conform to the Board's policy of preventing plant proliferation.

5.2.3 Views of the Board

The Board notes that the offer made by Amoco to Unocal for firm processing capacity and transportation at the Dome-Sinclair gas plant is subject to certain conditions which Unocal has claimed to be unacceptable.

With regard to the offer of processing capacity in the Dome-Sinclair gas plant, Amoco stated in its letter to Unocal dated 7 February 1989 and its letter to the Board dated 14 April 1989 that it is prepared to offer Unocal 141 x 10^3 m^3/d of firm processing capacity in the Sinclair plant, subject to plant partner approval. Amoco indicated in its letter to Unocal dated 7 February 1989 that the plant has the ability to process a maximum of approximately 1970 x 10^3 m^3/d of raw gas at the Dome-Sinclair gas plant with the addition of a screw compressor. However, because of declining reservoir pressures, the plant can effectively process a maximum of approximately 1400 to 1500 x 10^3 m^3/d of raw gas at the present time, and Amoco indicated that its sales contract with TCPL requires 1247 x 10^3 m^3/d of the currently available processing capacity.

Amoco also indicated that its share of the gas production from the Albright and Beaverlodge fields would be assigned to the TCPL contract. Therefore, it would appear that even in the most pessimistic case, there is a minimum of approximately 150 x 10^3 m^3/d of spare processing capacity at the Dome-Sinclair plant. This volume of spare capacity would seem to be sufficient to satisfy Unocal's processing requirements for its share of the Albright/Beaverlodge gas.

Furthermore, the Board is not convinced that Amoco, as the plant operator, would present an offer to process 141 x 10^3 m^3/d of processing capacity at the Sinclair gas plant to Unocal unless it had a reasonable degree of certainty that such capacity was available at the plant and its partners would approve of the offer. At the very least, the Board would expect that Unocal would pursue the matter of Amoco obtaining its partners' approval for the offer of this processing capacity prior to concluding that such capacity is not available.

The Board notes that Amoco's offer to assign firm transportation it has obtained from NOVA to Unocal is also subject to certain conditions which Unocal indicated it found unacceptable. The Board further notes, however, that Unocal stated that it understands that NOVA is willing to consider approving the assignment to Unocal of Amoco's service agreement for transportation from the Dome-Sinclair plant and, as well, may be prepared to consider the conversion of the type of transportation contained in this agreement from T-1 service to T-5 service. The Board believes that further investigation of these approvals by the applicant is warranted.

The Board notes that Amoco's offer of an assignment of firm transportation and Unocal's contract with NOVA at the proposed 6-17 site both have a service date of 1 November 1989. Since construction by NOVA is necessary to accommodate either of the contracts, the Board believes that the availability of firm NOVA transportation from either the existing Dome-Sinclair gas plant or the proposed 6-17 plant site by 1 November 1989 is equally uncertain, and should not be a deciding factor in determining whether or not the construction of a new gas plant in the Albright/Beaverlodge area is necessary in order for Unocal to process its gas.

In situations in which there appears to be more than one viable processing alternative presented to it, the Board must also consider the intangible benefits of approving a scheme which reduces or eliminates the potential impact on area residents when deciding which of those alternatives is the most desirable. If the applicant's preferred processing alternative could have real impacts on the residents that may be unacceptable, it is essential that the applicant thoroughly investigate the other processing options which may be available to it before concluding that these other options are not viable.

While the economic analysis submitted by Unocal shows a modest reduction in rate of return if the gas is processed at the Sinclair plant, the differences are not considered to be significant when considered in terms of the real benefits to the community if the gas plant were not constructed. All the available alternatives for development generate returns well above threshold levels.

In this case, the Board has to consider whether or not the concerns of the local interveners about the construction and operation of additional gas processing facilities in the Albright/Beaverlodge area would have a greater detrimental effect on their life-style than the impact on the applicant if the plant were not located in the area. The Board believes that the onus should be on Unocal to demonstrate to the satisfaction of the Board that the other processing options which appear to be available to it, including that of transporting its share of the Albright/ Beaverlodge gas to the Dome-Sinclair gas plant, represent an unacceptable economic cost, before the Board can approve any application to construct a new plant in this region. The Board is not convinced that the conditions stipulated by Amoco in its offers to Unocal are insurmountable obstacles to reaching an arrangement, or represent inordinate terms whereby Unocal's share of the Albright/Beaverlodge gas should not be processed at the Dome-Sinclair gas plant. Accordingly, the Board believes that this alternative remains as a viable processing option which warrants further investigation by the applicant.

6 CONCLUSION

Based on the evidence presented to it, the Board believes that processing Unocal's portion of the gas produced from the Albright and Beaverlodge fields at the Dome-Sinclair gas plant may be a viable processing alternative, and warrants further investigation by the applicant. The Board believes that the conditions which were specified by Amoco in the offers it made to Unocal for processing capacity in the Sinclair gas plant and a transportation assignment are not unreasonable, compared with a new plant, and the Board does not agree with the applicant's conclusion that these conditions render this processing alternative unacceptable. Continued discussions with Amoco regarding the specific details of these conditions are justified and could result in a resolution that is satisfactory to both Amoco and Unocal.

Furthermore, even if the applicant had adequately demonstrated that the construction of a new gas plant in the Albright/Beaverlodge area was required in order to process its gas, the Board is not convinced that the proposed 6-17 site is the most appropriate site. If processing of the gas at the Sinclair plant were not available, the Board believes that further consideration of the other locations which were suggested at the hearing is warranted.

Therefore, after considering all of the evidence presented, the Board is not convinced that Unocal has adequately demonstrated that a new gas plant is required in the Albright/Beaverlodge area at the proposed 6-17 location.

7 DECISION

Application 880830 is denied without prejudice to any future application that Unocal may submit.

DATED at Calgary, Alberta, on 15 August 1989.

ENERGY RESOURCES CONSERVATION BOARD

P. J. Mink, P.Eng.
Board Member

E. J. Morin, P.Eng.*
Board Member

E. G. Fox, P.Eng.*
Acting Board Member

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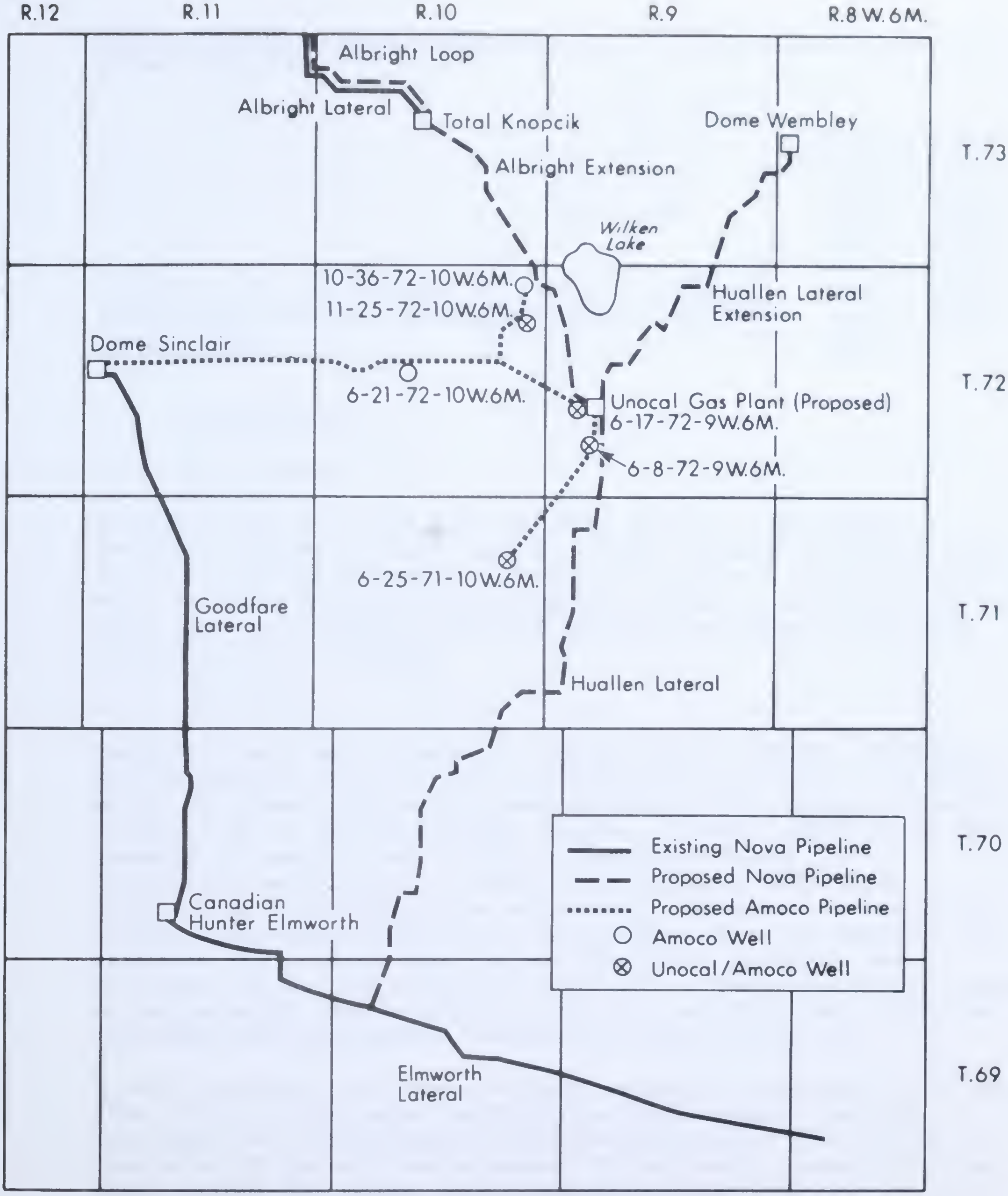
* E. J. Morin, P.Eng. and E. G. Fox, P.Eng. were unavailable for signature but concur with the contents and with the issuing of this report.



PROPOSED ALBRIGHT / BEAVERLODGE DEVELOPMENT
Application No. 880830
Unocal Canada Management Limited

D89-7
ERCB

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

Decision D 89-8
Applications 890574, 890576, 890577, 890578, 890579, 890795, 890796, 890797, 890798, 890799, 890800, 890801, 890802, 890803

STRATHFIELD OIL AND GAS LTD.
APPLICATIONS FOR WELL LICENCES
PROVOST FIELD

1 INTRODUCTION

1.1 Applications

Strathfield Oil & Gas Ltd. (Strathfield), applied to the Energy Resources Conservation Board (Board or ERCB), pursuant to section 2.020 of the Oil and Gas Conservation Regulations, for well licences to drill wells to bottom hole locations as listed in Table 1. The purpose of the wells would be to obtain production from the Dina Member of the Lower Cretaceous Mannville Group.

1.2 The Hearing

The Board issued well licences for applications No. 890574 and 890576 to 890579, and thereafter an intervention opposing the licences was filed by Mr. Roy Hanson, the surface owner of the northwest quarter of section 23(NW 1/4 of 23) and the southwest quarter of section 26(SW 1/4 of 26) township 37, range 4, west of the 4th meridian (37-4W4). His intervention was based on the impacts the wells may have on his agricultural operations and the environment. Subsequent to the filing of that intervention, Strathfield made application to the Board for the remaining well licences (Applications No. 890795 to 890803) and Mr. Hanson further registered his opposition to these applications based on the potential adverse effects on his farm and ranch operations, the environment and the health of animals and people in the area.

A public hearing of the application was originally scheduled for 24 May 1989. Prior to that date, the Board received a request from the intervener for a postponement of the hearing to allow time for the completion of his and other witnesses' spring farming operations. The Board decided that, given the circumstances of the intervener and his witnesses' and considering that the applicant was no longer trying to meet a government drilling incentive deadline of 30 June 1989, the hearing would be re-scheduled to commence 27 June 1989. At the outset of the hearing on the 27 June, a further request for postponement of the hearing was made by the intervener on the basis that the applicant should be required to more appropriately and adequately address the concerns of the intervener through more comprehensive studies. The Board decided that the applications were complete and should be tested through the hearing process.

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations Used in Report)		Witnesses
Strathfield Oil & Gas Ltd. R. A. Neufeld		F. Thompson K. McLelland A. Breakey J. A. Lore (of Jim Lore and Associates) F. Ceh (of Tempest Developments Ltd) D. M. Leahey, Ph. D (of Western Research Division of Bow Valley Resource Services Ltd.) T. Dabrowski, Ph. D (of Piteau Engineering Ltd.)
Roy Hanson J. W. Bodnar	Panel 1	R. Jones P. Nelson C. Prediger W. Blair H. Mock
	Panel 2	R. Hanson W. Hanson G. Lakevold W. Murphy
	Panel 3	C. Wallis, P. Biol. (of Cottonwood Consultants)
Energy Resources Conservation Board Staff C. S. Richardson C.J.C. Page R. Paulson, C. E. T. E. Shima, P.Geol.		

The public hearing of the applications was held in Provost, Alberta on 27 and 28 June 1989 before N. A. Strom, P.Eng., E. J. Morin, P.Eng., and C. A. Langlo, P.Geol.

Prior to the conclusion of the hearing, the Board and the hearing participants visited the proposed well site surface locations and the general area.

B. Pretula, R.E.T., representing the Groundwater Protection Branch of Alberta Environment, and Jim North of the Land Conservation and Reclamation Council (LCRC), attended the hearing for purposes of assisting Board staff.

2 BACKGROUND

The proposed wells are located approximately 13 kilometres (km) south and 2 km west of the hamlet of Cadogan. The climate in the area is relatively semi-arid and in recent years has tended to have below average precipitation.

Soils in the area are extremely sandy and poorly developed, with a relatively poor water and nutrient holding capacity. As well, topsoils are too thin to be practically improved for cultivation. The landscape is gently rolling with the exception of a prominent glacial esker approximately 1 km wide by several km long bordering the northern edge of Sounding Lake. The esker trends in a NW to SE direction and is located south of and adjacent to the area of the proposed wellsites. Land use in the area is generally for pasturing cattle. Selective clearing of bush and seeding of these areas with non-native grasses is being evaluated as a means of improving the grazing capacity of the land.

Shallow alkaline lakes are prevalent in the area. As shown in Figure 1, Soapy Lake is located immediately to the NW of the 5A-26-37-4 W4 surface location and Sounding Lake is located approximately 350 metres (m) SW of the 2-23-37-4 W4 surface location, on the south side of the glacial esker. A shallow water table rises to within 2 to 3 m of the land surface in the area south and east of Soapy Lake. A spring, known locally as the Black Spring or Big Spring, discharges water near the edge of Sounding Lake on the south side of the esker.

Oil and gas wells are scattered throughout the area. In township 37-4 W4M, there have been 17 Viking gas wells drilled during the period from 1951 to 1973. More recently, the discovery of oil has led to the drilling of 15 wells in sections 15, 16, 17, 20 and 21, and approximately 28 wells in sections 23, 26, 27 and 34.

The geological zone of interest for Strathfield's proposed wells is the Dina Member of the Lower Cretaceous Mannville Group. The reservoir occurs within a sandstone unit which trends generally northwesterly, with the major portion of pool development in section 27-37-4 W4M.

The area is subject to 4 hectare (ha) (10 acre) well spacing. Specifically, Board Order No. SU 1606 allows for one quarter legal subdivision (Lsd) Lower Mannville oil well spacing with the target area being 50 metres within the boundaries of each 1/4 Lsd or 4 ha drilling spacing unit (DSU). As well, Board Orders No. GTO 8915, GTO 8916 and GTO 8917 allow for target area flexibility by suspending the SU 1606 target area. These orders permit interwell distances as small as 100 m and require that production be taken from at least 50 m inside the boundaries of the GTO areas. See Figure 2.

3 ISSUES

The Board considers the issues with respect to the applications to be

- o need for the wells and well spacing,
- o proposed development plan,
- o surface water and groundwater impacts,
- o air quality impacts,
- o land use and habitat impacts,
- o future production operations, and
- o communications.

4 NEED FOR THE WELLS AND WELL SPACING

4.1 Views of the Applicant

Strathfield described the target Dina Zone as a lenticular sand bar about 20 m thick in the centre and thinning out to less than 2 m at the edges. It stated that the water-deposited sand had a fairly strong northwesterly trend and sharp, serrated edges. The reservoir was described as averaging 4.2 m of oil pay overlying a 5 to 15 m thick water leg. Strathfield submitted that there would be natural pressure support from the water leg, a tendency for water coning, and high rates of water production in some wells.

Strathfield reported a low gas/oil ratio of about 10 to 15 m^3/m^3 for most wells in the pool, with solution gas containing hydrogen sulfide (H_2S) in concentrations ranging up to 8.8 moles per kilomole (0.88 per cent). It stated that the produced oil was of fairly good quality with a fairly high wax content, and a gravity of 28° to 30° API. Strathfield stated that for efficient recovery of hydrocarbons from the Dina Member, 4 ha well spacing as previously approved by the ERCB was required.

Strathfield stated that at present there are 20 wells in the main part of the pool and 4 abandoned edge wells. It estimated another 30 wells would be required to fully develop the pool on 4 ha spacing. It expected the pool to encompass portions of sections 23, 24, 26, 27, 33, 34 and 35, 37-4 W4M and extend into sections 14 and 22. Strathfield estimated the average primary recoverable reserves per 4 ha DSU to be about 10 000 to 24 000 m^3. It stated that overall about 476 200 m^3 additional reserves would be recovered by developing on 4 ha spacing. Strathfield suggested that the average economic life of a well would be 5 to 7 years with a high rate of recovery owing to the strong water drive. It expected a high success rate for the proposed wells in encountering producible reserves.

Strathfield proposed three main points in support of its need for the wells. The first was the commercial value of the reserves both to the applicant directly and to the adjacent community in terms of employment, utilization of local supplies and services, tax revenues from property assessment, and royalty and mineral taxes paid to the Crown and to freehold mineral owners.

The applicant stated that the well in 2-26-37-4 W4M (well 2B-26) was required in order to fulfill a freehold mineral rights agreement between Strathfield and Amoco Canada Resources Ltd.

The third area of need for the wells was described by Strathfield as an "informational need". Strathfield explained that the normal practice would be to shoot "3-D" seismic in order to delineate reservoir extent and facilitate planning of optimum infill drilling and production facilities. However, it stated that due to the refusal of some surface occupants to allowing seismic activity on their land, it had limited seismic control in the area and therefore required some of the wells to help define the pool boundary. Strathfield stated that the 2-23 well would be drilled on a seismic shot-point to test a separate seismically-interpreted pool.

4.2 Views of the Intervener

The intervener did not question the technical aspects of successfully drilling and producing the subject wells. However, a member of the intervener's panel questioned the need for the reduced spacing, suggesting that the motivation was accelerated pool depletion rather than a need for efficient recovery.

4.3 Views of the Board

The Board accepts the technical merits of the applicant's pool development proposal and that the applied-for bottom hole locations are required as part of this development. The Board further concurs that development of the pool on 4 ha spacing will increase the prospect for somewhat improved oil recovery.

5 PROPOSED DEVELOPMENT PLAN

5.1 Views of the Applicant

Strathfield applied to license 14 wells to be drilled from 5 surface locations, as outlined in Table 1 and shown on Figure 1. All surface leases with the exception of 13D-23, 13B-23 and 15C-23 have been constructed. Strathfield stated that it would prefer multi-well pad drilling rather than single wells when drilling on 4 ha spacing, whenever feasible, for the following economic and environmental reasons:

- o Pad drilling is technically feasible and efficient.
- o The amount of surface land disturbance, whether on agricultural or native grassland, is minimized, and there is greater flexibility in locating the pad surface lease.
- o Surface acquisition costs are minimized.
- o Costs for movement of rigs and equipment are reduced.
- o Flowlines and gathering systems can be optimized, while easement and ditching requirements are minimized.
- o Lease roads are minimized and traffic is reduced.
- o Operating efficiency is increased by allowing the well operator to check multiple wells at one stop.

Strathfield estimated that drilling, completing and equipping a single vertical well would cost approximately $257,000, while a directional well would cost about $280,000 or an additional cost of $22,000 to $23,000. However, it reported that there would be significant savings from a multi-well pad based on the economic considerations outlined above, to offset the additional costs of directional drilling.

5.2 Views of the Intervener

The intervener acknowledged that pad drilling could substantially ease some of the land and other environmental impacts related to oil recovery operations in the area.

Mr. Wallis expressed approval of multi-well pad drilling while cautioning that site and road locations should still be carefully located and monitored in order to minimize environmental impacts. He stated that a major road into site 5A-26 near Soapy Lake could adversely impact the nesting and feeding habitat of some species of shore birds.

Concern about pad drilling was expressed by the intervener in that sump liners might not be adequate to withstand the pressure of multiple use during the drilling phase. The intervener also voiced concern that near surface circulation could affect other wells drilled from the same pad. (This issue as it relates to surface water impacts is dealt with in Section 6.0.)

5.3 Views of the Board

The Board strongly favours the use of pad drilling in areas of relatively close well spacing (4 ha or less) where surface impacts can otherwise be very significant. This is especially true where gathering and control of emissions is important and where the land surface is sensitive due to soil conditions, or where impact on the natural habitat is important. In this particular application, all of these factors apply and the Board therefore agrees with the applicants proposed development plan.

6 SURFACE WATER AND GROUNDWATER IMPACTS

6.1 Views of the Intervener

The intervener expressed a number of general concerns with respect to surface water, shallow groundwater, and deeper aquifers usable for residential and agricultural purposes. Problems of declining water quality and quantity were identified. The intervener considered Strathfield's knowledge of hydrologic conditions to be incomplete and believed that further knowledge of the hydrologic characteristics would aid in formulating suitable mitigative measures to lessen impacts and reduce the potential for irreparable damage. The intervener also noted the significance of Belly River sand aquifers to area residents and wanted assurance that this aquifer would be fully protected from damage resulting from the drilling of oil wells or seismic activity. Specifically, the intervener stated that directional wells drilled from the 5A-26 lease would be acceptable if the Belly River aquifers were protected from contamination by the use of deeper surface casing.

The intervener also expressed concern about on-site spills contaminating groundwater. He proposed mitigative measures such as trucking away drilling fluids, spreading a clay layer over permeable sandy lenses to provide a barrier, and test hole monitoring of groundwater at operations near Soapy Lake.

Mr. Wallis noted that oil well drilling and the potential for spills near Soapy Lake represented a risk to shoreline habitat and water quality. He expressed concern that a spill could adversely affect the breeding area and feeding habitat of shore birds such as the endangered Piping Plover. He further stated that any change in local water table elevation as a result of natural drought or oil and gas developments could have an impact on shore birds.

The intervener expressed concern that the Black Spring could be irreversibly damaged through drilling the 2-23 well. He noted that the spring had already undergone a decrease in discharge over recent years. The intervener submitted that monitoring dugouts on his lands and the spring prior to and after drilling completion would be a necessary step in ensuring that groundwaters were fully protected.

The intervener stressed that the vitality of grass and other vegetation was linked to the presence of a high water table in the surficial soils. He believed that a thorough knowledge of the groundwater hydrology,

extending from Soapy Lake to the prominent esker and the Black Spring on the northern rim of Sounding Lake, would help to ensure that the proposed drilling and oil production operations would not alter or damage that hydrologic system.

6.2 Views of the Applicant

Strathfield was confident that its operations would not have an impact on the quality or quantity of water in the dugouts or produced at the Black Spring in the NE 1/4-14-37-4 W4 (see Figure 1). However, Strathfield indicated that possible sources of surface and groundwater impact could include disturbance of the land surface, which might influence recharge rates; spills of hydrocarbons or chemicals; losses of toxic substance-contaminated drilling mud on the surface or during drilling; leakage from improperly constructed wells; toxic mud additives leaking from mud pits, and improper disposal of wastes produced during drilling. Accordingly, in order to safeguard surface and groundwater during the drilling program, it proposed the following steps:

- The well pad would be bermed in accordance with good oilfield practise, and diked and contoured to contain and prevent escape of surface water runoff.

- Test pits would be dug to a 3 m depth in the sump area to identify the presence of any groundwater. If detected, the sump would be dug to a depth above the groundwater level, and a sump liner installed.

- A conductor barrel would be pile-driven to refusal depth, generally between 12 and 18 m in this area.

- Surface hole would be drilled with fresh water and natural bentonite clay, surface casing set to a minimum of 135 m, or deeper as necessary to intersect a competent rock unit, and cemented back to surface.

- The production hole would be drilled using a fresh water natural clay gel system. If the well was successful, production casing would be run and cemented back to surface.

- Sump fluids would be disposed of off-lease.

Strathfield indicated that it would be willing to modify such drilling practices as were deemed reasonably necessary in order to satisfy water protection concerns.

Strathfield further proposed doing a water analysis on samples obtained from the Black Spring and the two dugouts on Mr. Hanson's land, both prior to and after drilling wells in the vicinity in order to monitor possible changes in water quality. However, Strathfield indicated that a properly installed well, whether straight or directionally drilled, should not cause adverse impacts on groundwater aquifers. Strathfield stated that normal drilling time for surface hole in this area would be from four to six hours, with surface casing cemented in place in ten to twelve hours. The total drilling and completion or abandonment of the

wells would occur within a five to seven day time period. It stated that if drilling or servicing operations caused a loss of water production from the spring, Strathfield would undertake reasonable necessary steps to replace lost water production.

In response to concerns for surface water and shallow groundwater contamination through spills, Strathfield maintained that any spills would be cleaned up before they could cause damage to the dugout near pad 5A-26 or to the Black Spring. Strathfield considered monitoring to determine groundwater parameters to be unwarranted. However, in response to questioning, it outlined a possible plan of groundwater monitoring which could be located around each drilling pad to monitor changes in the hydrologic regime.

6.3 Views of the Board

The Board shares the concern of local residents that groundwater supplies in the application area must be fully protected. In that regard, the Board notes that the applicant intends to drill the surface hole with fresh water mud and to set surface casing below the unconsolidated material. The Board notes the short time period between drilling surface hole and setting of surface casing and the minimal total time for drilling and well completion in this area. The Board concludes that the combination of the very short formation exposure time, the use of fresh water based drilling fluids, and cementing of both casings to surface will provide full protection to both the shallow and deeper aquifers.

With respect to the Black Spring, the Board does not believe that any impact would result from drilling the proposed wells since the nearest well (the 2-23 well) is over 400 m from the spring discharge area.

The Board believes that changes in the local hydrologic system would be governed by cyclic recharge and dissipation caused primarily by cyclic variations in annual precipitation, evaporation from surface water and evaporation/transpiration from vegetation. Among the variables, changes in precipitation from year to year may well be the most dominant factor in the system. The Board is very doubtful that the presence of cased, cemented oil wells would have any bearing on the cyclic recharge and dissipation that will occur in such a system.

The Board notes that spills or leakage from sumps, drilling mud and fluids containing salt or oil, or chemicals at battery sites would be potential sources of contamination of shallow groundwater aquifers. In consideration of the sandy nature of the soils and surficial deposits, and the resulting opportunity for rapid infiltration of shallow aquifers by any spills, the Board would require that

- no earthen-pit sumps be constructed and all sump fluids be diverted to and contained in steel tanks,

- all fluids from drillstem and production tests be contained in steel tanks,

- all sump, drillstem and drilling fluids be disposed off-site under the direction of the ERCB's Wainwright Area Office staff and the local representative of the LCRC of Alberta Environment.

Additionally, the standard practices of dyking and containment of runoff water at the well pad battery sites should protect surface waters from potential contamination.

In order to ensure that the proposed development does not impact usable water supplies in this area, the Board will require Strathfield to submit a proposal for an appropriate groundwater monitoring system to the ERCB prior to drilling the applied for wells. In addition to the foregoing, the Board will also require that the applicant meet with the intervener and Alberta Environment, Groundwater Branch, to discuss the design and installation of this system.

7 AIR QUALITY IMPACTS

7.1 Views of the Applicant

In response to concerns expressed by the interveners respecting air quality, Strathfield submitted that it would comply with all regulations and standards intended to control hydrogen sulphide (H_2S) and sulphur dioxide (SO_2) emissions and, further, that it would undertake to construct its facilities in such a manner as to eliminate any emissions and potential odors. It stated that until production from the pool was large enough to warrant the construction of a central facility, group well batteries would be utilized at each drilling pad and be equipped with

- a two-phase separator with the overhead gas tied to a flare stack,
- production tanks with gas boots tied to a flare stack,
- a minimum 40 foot flare stack with a continuous propane pilot, and
- pumpjack engines that will automatically shut down if the flare stack pilot is unlit due to lack of fuel.

In addition to the above, Strathfield submitted that the wellsites would be monitored daily, and in the event of a contravention of ambient air quality standards, the facility causing the problem would be shut-in until the problem was corrected.

The applicant stated that ground level SO_2 concentrations that could be produced from any one of the five wells with the highest flow rates would be far below Alberta Environment standards and would have no adverse effect on the environment or the residents of the area. It further submitted that the maximum total sulphate deposition in the area, a majority of which was from atmospheric background sources plus small amounts from the battery flare stacks, would be in the order of 16 kilograms per ha. It contended that the potential for acidification would therefore be negligible.

Strathfield also examined the possibility of an equipment failure that would cause a release of H_2S. It calculated that in a worst case scenario, 10 m downwind from the source of the release, H_2S concentrations could be as high as 55 parts per million (ppm) which would cause eye and lung irritation but would not be sufficiently high to be life threatening. The concentrations would quickly drop such that at 100 metres downwind they would be 2 ppm and beyond 2000 metres they would be less than 0.01 ppm. It acknowledged that even these lowest concentrations would be detectable as an odor.

It was Strathfield's position that in view of the relatively small amounts of H_2S present in the gas, further studies into the potential effects of its operations on air quality were not warranted.

In reply to questions, Strathfield indicated that tentative consideration had been given to construction of a central battery facility that would allow for better control of emissions. However, delineation of the field would be necessary for the proposal to be pursued.

7.2 Views of the Intervener

Strong concerns were expressed by the intervener respecting the potential for emissions of H_2S, and the continuous emission of SO_2 to the atmosphere. Mr. Hanson submitted that control of H_2S emissions in the area is not satisfactory and that odors are an ongoing problem. Several witnesses for the intervener stated that odors were noticeable in the areas around Gooseberry Lake, Provost, and at existing Strathfield and other facilities in the area.

Concerns were expressed by members of the intervener's panels as to the health implications of H_2S. The intervener made reference to conflicting results of studies from the Pincher Creek area on the health impacts of H_2S gas. Members of the intervener's panels suggested that the standards for control of H_2S emissions should be reviewed and more study should be conducted into the long term effect of H_2S on people and the environment.

The intervener submitted that a central facility where fluids could be pipelined from the wells would greatly assist in control of H_2S gas as it would eliminate the individual flare stacks on each well and pad location. Members of the intervener's panels stated that the individual well flare stacks are prone to being extinguished and thus create a hazard.

7.3 Views of the Board

The Board accepts the estimates for H_2S and SO_2 levels predicted by Strathfield for the proposed wells and notes that these levels are well within established air quality standards. As well, Strathfield undertook to design its well and pad battery installations in such a manner that gas from separators and storage tanks at each site would be flared at a 40 foot flare stack. With all systems working smoothly, this should limit objectionable emissions to minor fugitive odors such as small leaks from valve glands. The Board recognizes that equipment

such as gas boots will fail from time-to-time and the best solution to that problem is a conscientious on-site operator supported by company management committed to establishing and maintaining good relations with the community.

The Board believes that the approach proposed by the applicant is acceptable initially until the field has been more or less delineated. After that time, however, the Board anticipates that installation of a central facility would offer a number of advantages including better control and flaring of gas and vapors. The Board would therefore require that Strathfield submit a feasibility study of a central facility after the proposed wells have been drilled and placed on production.

8 LAND USE AND HABITAT IMPACTS

8.1 Views of the Applicant

Strathfield submitted that with pad drilling and minimum soil stripping, its operations would have a minimal adverse effect to the land surface and to Mr. Hanson's agricultural operations. It stated that on level ground only 30 per cent of the lease area would be stripped, but as topographic relief increased, more of the surface lease may have to be stripped to accommodate increased cut and fill. Strathfield submitted that access roads would not be stripped unless dictated by the topography. In all areas of stripping, the soil would be stockpiled for use in restoration upon abandoment. Areas of leases initially disturbed but not required for production operations would be promptly recontoured and reseeded.

Strathfield noted that once the land surface in this area is disturbed it is not possible to fully reclaim it back to its native state. However, by following some of the recommendations of the Special Areas Board, the land could be conserved and erosion controlled. It believed that a good seed mix for the proposed well locations would be Russian Wild Rye, based on its experience in restoring an abandoned well at Lsd 16-22-37-4 W4. It stated that this grass will establish and remain viable for many decades, is resistant to overgrazing and will maintain soil structure and chemistry as well as native grasses.

8.2 Views of the Intervener

The intervener submitted that there have been and will continue to be numerous adverse impacts to the land surface and its use for agricultural operations. Included among these were intrusion of leases on native grasslands, dust drifting from roads into adjoining pastures, the possibility of sump liner failures, introduction of weeds from uncleaned seed mixes used for lease re-seeding, and the use of Russian Wild Rye for reclamation leading to overgrazing of lease areas. The intervener suggested that many of the weeds that grow on wellsites were introduced through the seed mix used for reclamation. The only way to control the weeds would be to ensure a clean seed mix as Mr. Hanson would not agree to use of herbicides on his land. The intervener stated that most of the proposed and existing surface leases are located on

areas of prime grassland in areas susceptible to wind erosion. Further, the disruption of the soils on the leases is far greater than the disruption caused by agricultural operations.

Respecting removal of trees and shrubs, Mr. Hanson submitted that his ranching operation requires that certain areas of brush be selectively cleared, the soil surface given light cultivation and seeded to fall rye. This provided increased grazing capacity.

The intervener stated that he would see many benefits if Strathfield were to construct a pipeline to transport crude oil out of the area. He stated that this would minimize the potential for spills, heavy traffic on the roads, odors and dust.

Mr. Wallis identified concerns for the shorebird populations in the vicinity of the 5A-26 surface location, the fragility of the soil and its susceptibility to erosion once disturbed, and the difficulties in reclamation in this area. He stated that oil and gas development is incompatible with maintaining the habitat and ensuring continuing stability of the ecosystem in this area. He submitted that if development were to occur, the proposed wellsites should be located as far away as possible from the wetland areas and placed in areas where the soil is more developed, and is less sensitive to erosion.

8.3 Views of the Board

Several of the proposed wellsites are located on leases that have already been built, so that many of the surface impacts identified by the intervener already exist. The drilling of additional wells from an existing well pad would result in very little incremental impact to the land surface.

Therefore, the Board is satisfied that the drilling of 4C-26, 4D-26, 5B-26 and 5C-26 from the existing 5A-26 location as proposed by Strathfield could be done with very little additional land disturbance. Similarly the drilling of 4A-26, 3B-26 and 14C-23 from 13D-23, and 14A-23, 14D-23, 3A-26, 2B-26 and 15C-23 from 15C-23 will minimize impact.

With respect to the 13B-23-37-4 W4 location, the Board notes that although Strathfield has a surface lease at this location to drill a vertical well, such development would be at odds with pad drilling to reduce impacts. The Board believes that it would be feasible to drill the 13B-23 well from either the existing 13C-23 pad location or the proposed 13D-23 pad location.

9 FUTURE PRODUCTION OPERATIONS

9.1 Views of the Applicant

Strathfield submitted that if sufficient volumes of production are established, a central battery would be constructed in the vicinity of the 7-27-37-4 W4 well location and all production from the existing, proposed and future well locations would be pipelined to the central

battery. This would permit removal of all wellsite battery equipment with the exception of the pumpjacks. Strathfield stated that a central facility would allow for all produced water to be reinjected into the Dina zone at the central site, and for gas to be gathered and flared at a single flare stack. Vapor recovery equipment could be installed on tanks and truckloading facilities, and the clean oil would be stored in tanks from which it would be trucked to a pipeline terminal for sale.

Strathfield was unable to commit to a time at which it would proceed with construction of the facility but stated that volumes in the order of 300 to 400 m^3 of oil per day would allow it to construct the facility. It stated that currently it is producing 126 m^3 oil per day from its existing wells in the pool and if the proposed additional wells encounter typical production volumes, it would consider starting construction of some form of central facility. However, Strathfield could not identify if and when a market pipeline system could be economically justified to replace hauling of oil by tanker trucks.

9.2 Views of the Intervener

The intervener did not state a position respecting a central battery although many of the witnesses recognized the merits of a central facility as opposed to several battery sites. Several of the intervener's witnesses identified problems associated with single well batteries in the area, including odors, heavy traffic, dust from road allowance and lease roads, oil spills and the potential for accidents on roads.

9.3 Views of the Board

The Board believes that construction of a central facility would assist in several ways to reduce air and land impacts. Among other benefits would be much greater assurance of continuous gathering and flaring of gas and control of fugitive odors; considerably reduced truck traffic and elimination of excess dust; and the cost advantages of group separation and disposal of produced water through a disposal well at the central facility. Additionally, the feasibility of installing a crude oil market pipeline may emerge with the prospect of eliminating truck tanker traffic from local roads.

Accordingly, the Board will require Strathfield to submit proposals for a central facility and a water disposal well, and a feasibility study of a crude oil market pipeline within a year of completing the wells applied for in the present applications.

10 COMMUNICATIONS

During the hearing, the interveners on occasion expressed concerns that demonstrated a lack of understanding of good oilfield practise and the applicant's intentions in that regard. On the other hand, the applicant confirmed that it was very anxious to proceed with the development of the reserves that it believed underly its properties. Under these circumstances it is not surprising that a lack of meaningful

communication between the applicant and the intervener was very apparent.

The Board is aware that a Provost Operators Committee was recently formed to address the need for communication between the public and the oil and gas industry active in the area. Meetings with the public have been held and more are planned.

The Board urges both the applicant and the intervener to participate in the committee's activities. For the public, these are an opportunity to express their concerns and have them addressed. For the industry, it is an opportunity to demonstrate that they have an interest in the concerns of the community and they are prepared to respond in a meaningful way.

11 DECISION

The Board approves the well license applications 890576, 890577, 890578, 890579, 890795, 890796, 890797, 890798, 890799, 890800, 890801, 890802 and 890803 subject to the requirements stated in sections 6.3, 7.3 and 9.3.

The Board denies application 890574 for the reasons stated in section 8.3.

DATED at Calgary, Alberta, on 8 September 1989.

ENERGY RESOURCES CONSERVATION BOARD

N. A. Strom, P.Eng.
Vice Chairman

E. J. Morin, P.Eng.
Board Member

C. A. Langlo, P.Geol.
Acting Board Member

TABLE 1: APPLICATIONS FOR WELL LICENCES
PROVOST FIELD

Application No.	Well Name/Bottom Hole Location	Surface Location
890574	Strath et al Provost 13B-23-37-4	Lsd 13-23-37-4 W4M
890576	Strath Polaris Provost 5B-26-37-4	Lsd 5-26-37-4 W4M
890577	Strath Polaris Provost 4C-26-37-4	Lsd 5-26-37-4 W4M
890578	Strath Polaris Provost 4D-26-37-4	Lsd 5-26-37-4 W4M
890579	Strath Polaris Provost 5C-26-37-4	Lsd 5-26-37-4 W4M
890795	Strath Polaris Provost 3B-26-37-4	Lsd 13-23-37-4 W4M
890796	Strath Polaris Provost 15C-23-37-4	Lsd 15-23-37-4 W4M
890797	Strath Polaris Provost 2B-26-37-4	Lsd 15-23-37-4 W4M
890798	Strath Polaris Provost 14D-23-37-4	Lsd 15-23-37-4 W4M
890799	Strath Polaris Provost 14A-23-37-4	Lsd 15-23-37-4 W4M
890800	Strath Polaris Provost 3A-26-37-4	Lsd 15-23-37-4 W4M
890801	Strath Polaris Provost 4A-26-37-4	Lsd 13-23-37-4 W4M
890802	Strath Polaris Provost 14C-23-37-4	Lsd 13-23-37-4 W4M
890803	Strath Polaris Provost 2-23-37-4	Lsd 2-23-37-4 W4M

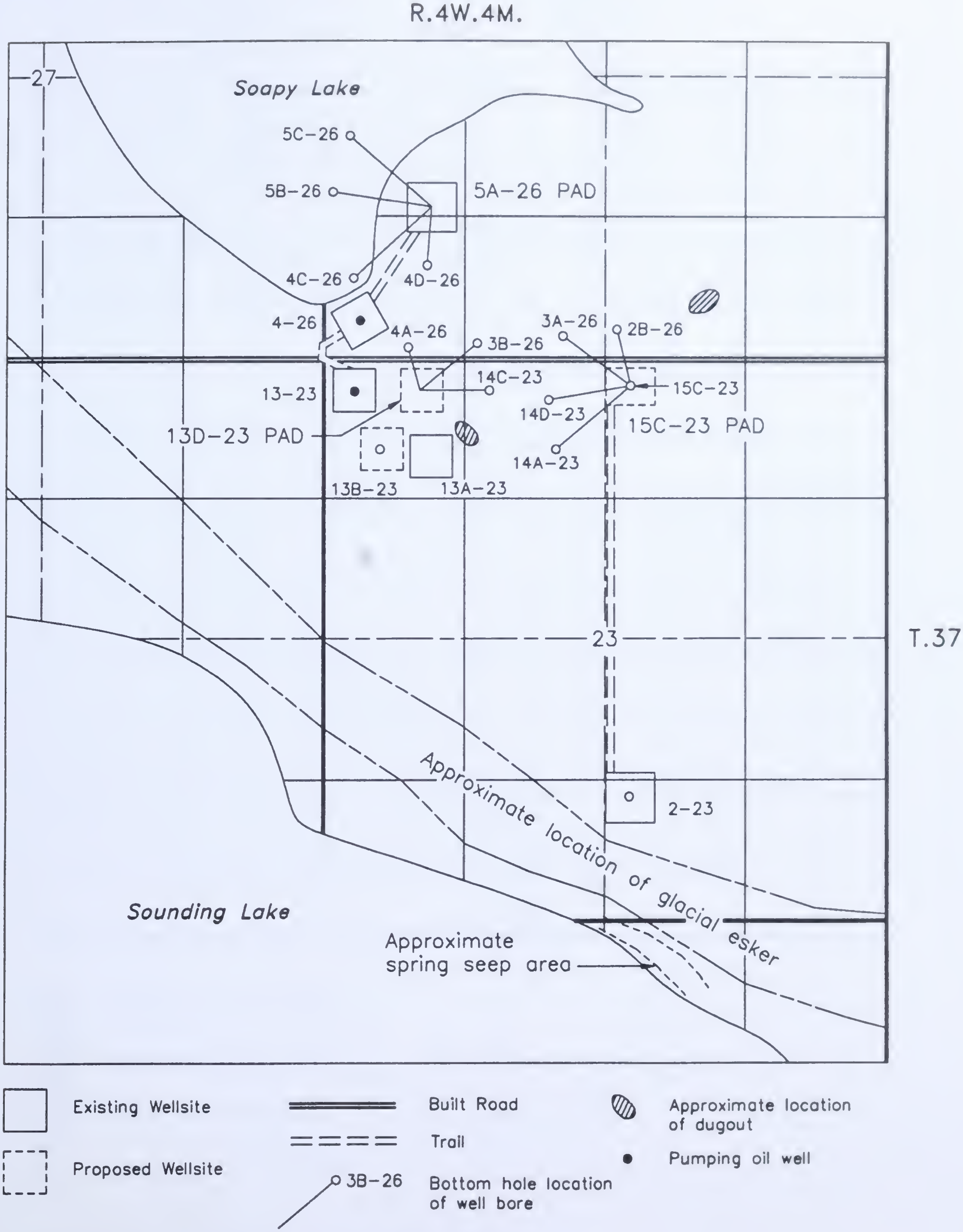
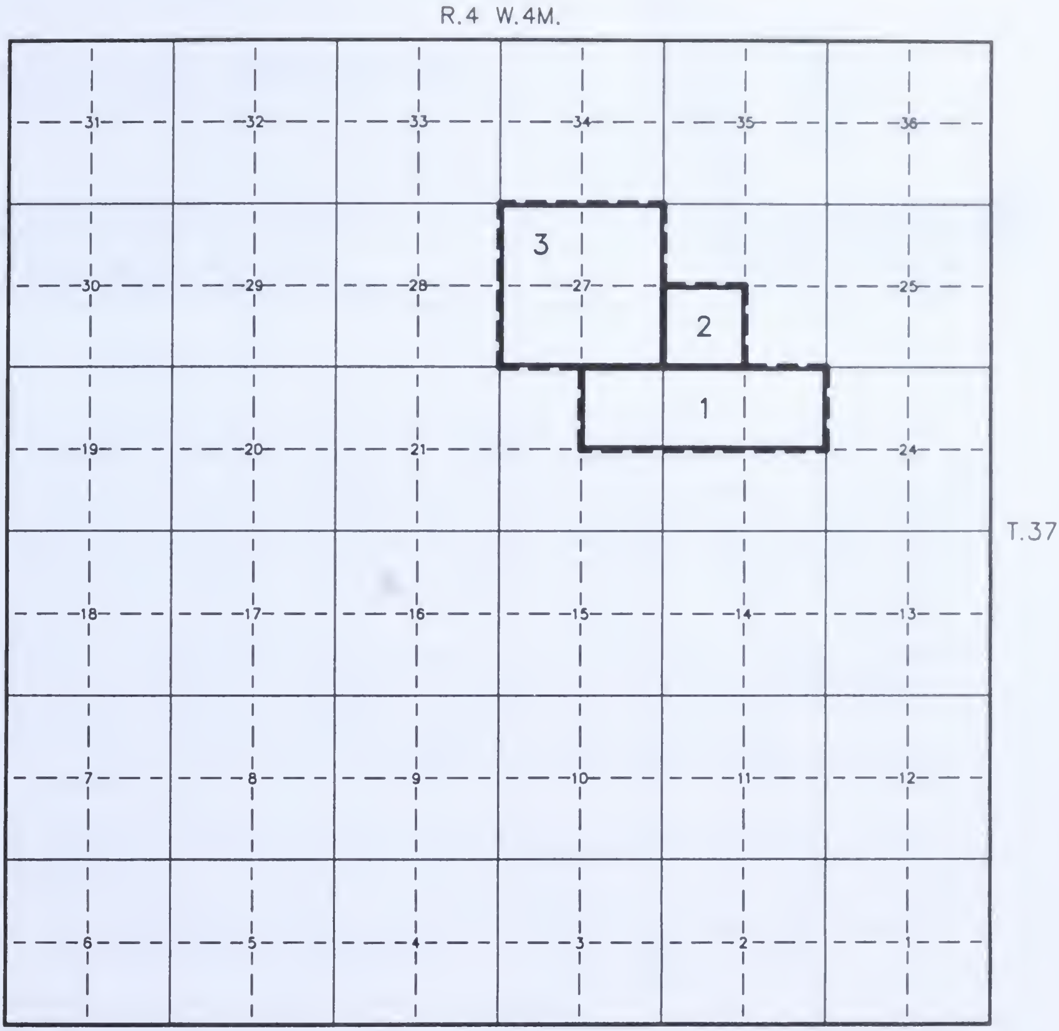


FIGURE 1 PROPOSED AND EXISTING WELLSITE PADS
Application No. 890574, 890576–890579, 890795–890803
Strathfield Oil and Gas Ltd.



1 Order No. GTO 8915

2 Order No. GTO 8916

3 Order No. GTO 8917

Spacing Unit SU 1606

FIGURE 2 SPACING UNIT AND GTO'S

D89-8

ERCB

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

HEARING DATE AND PROCEDURES
AMOCO CANADA RESOURCES LTD.
CHEVRON CANADA RESOURCES
KAYBOB SOUTH BEAVERHILL LAKE A

Memorandum of Decision
Application 880332
Application 880421

1 INTRODUCTION

Amoco Canada Resources Ltd. (as successor in interest to Hudson's Bay Oil and Gas Company Limited) and Chevron Canada Resources applied to the Energy Resources Conservation Board separately for amendment of Approval No. 4044 to curtail dry gas cycling and increase gas sales (hereinafter referred to as blowdown) in Kaybob South Beaverhill Lake Gas Units No. 2 and 3, respectively. The Board decided these two applications should be considered concurrently at a public hearing.

Because of differing views expressed to the Board with respect to timing of the hearing and the issues to be considered, the Board convened a pre-hearing meeting. The meeting was held on 13 June 1989 before a Board panel comprised of G. J. DeSorcy, P.Eng. (Chairman), N. A. Strom, P.Eng., and J. P. Prince, Ph.D. The attendees are listed in Appendix I.

The following matters, as set out in the notice of the meeting, were considered:

(a) the appropriate timing of the hearing and deadlines for filing of interventions and responses,

(b) the scope of matters to be considered,

(c) any special procedures needed to facilitate participation, and

(d) any other matters suggested.

A brief outline of each matter, and the Board's decision on each, follows.

2 TIMING OF THE HEARING AND DEADLINES

There was a reasonable consensus for a hearing date in early September 1989. Accordingly, the Board has set the hearing date for 6 September 1989. There was also reasonable agreement on filing deadlines for interventions and responses, for which the Board has set 7 August 1989 and 28 August 1989, respectively.

3 SCOPE OF MATTERS TO BE CONSIDERED

Conservation of resources (as the technical justification for blowdown) was generally accepted as an issue for the hearing.

A number of ancillary, equity-related issues were raised, including inter-unit drainage, the need for a gas marketing agreement, and availability of gas transportation. Views differed on whether or not these matters should be considered at the hearing.

The Board has decided to hear submissions regarding any of these matters, in order to determine their relevance to the decision. In so doing, the Board would not necessarily be bound to institute remedies to these ancillary issues.

4 SPECIAL PROCEDURES NEEDED TO FACILITATE PARTICIPATION

Amoco proposed, and others agreed, that the Board should, in effect, follow its standard procedures for hearing applications concurrently. These procedures are intended to avoid duplication and minimize the number of separate appearances by each applicant and intervener.

The Board expects to follow these standard procedures, but with the option to make adjustments closer to the hearing date if warranted by a change in circumstances. All registered participants will be kept advised of any changes to the hearing procedure.

5 OTHER MATTERS

Amoco requested leave to apply for wellbore and well-site modifications and pipeline permits necessary for blowdown, prior to blowdown approval, on the basis that this would be at Amoco's own risk.

The Board is prepared to consider applications for these kinds of facilities in the normal manner on their own individual merits, and prior to the blowdown applications. The Board will, however, give other operators in the pool an opportunity to object. Should these applications be approved, the approval would emphasize that Amoco proceeds entirely at its own risk, and that the Board would have no consideration for Amoco's investment in reaching a decision on the blowdown application.

DATED at Calgary, Alberta, on 21 June 1989.

ENERGY RESOURCES CONSERVATION BOARD

G. J. DeSorcy

G. J. DeSorcy, P.Eng.
Chairman

N. A. Strom, P.Eng.
Vice Chairman

J. P. Prince

J. P. Prince, Ph.D.
Board Member

Mr. Strom was not available to sign this decision, but is in agreement with it.

APPENDIX I

THOSE WHO APPEARED AT THE PRE-HEARING MEETING

Participants	Representatives
Chevron Canada Resources	D. Rowbotham J. Stein
Amoco Canada Resources Ltd. and Amoco Canada Petroleum Company Ltd.	R. Neufeld V. Carson
Mobil Oil Canada	A. Hollingworth L. Anderson
Petro-Canada Inc.	S. Miller W. Leach
BP Resources Canada Limited	J. Rankin P. Harrison
Western Gas Marketing Limited	J. Maher K. Martin K. Rawson
Consolidated Natural Gas Limited	P. Leier P. McMillan
Energy Resources Conservation Board staff	A. Broughton H. Keushnig K. Hunt D. Peet

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

AMOCO CANADA RESOURCES LTD.
CHEVRON CANADA RESOURCES
KAYBOB SOUTH BEAVERHILL LAKE A

Interim Decision D 89-9
Application 880332
Application 880421

1 INTRODUCTION

Amoco Canada Resources Ltd. (as successor in interest to Hudson's Bay Oil and Gas Company Limited) and Chevron Canada Resources applied separately for amendment of Approval No. 4044 to curtail dry gas cycling and increase gas sales (hereinafter referred to as blowdown) in Kaybob South Beaverhill Lake Gas Units No. 2 and 3, respectively. The applications were considered concurrently at a public hearing held on 6 and 7 September 1989 with N. A. Strom, P.Eng., E. J. Morin, P.Eng., and J. D. Dilay, P.Eng. (acting Board Member) sitting. The participants are listed in Appendix I.

At the opening of the hearing, all parties agreed that only issues pertaining to the technical aspects of the applications, primarily focusing on energy conservation, would be heard at this time. Issues pertaining to transportation and marketing would be tabled pending further negotiations among the working interest owners and, only if necessary heard at a later date. Both applicants expressed the need for an expeditious decision on the applications and hence this interim decision report is being issued.

2 INTERIM DECISION

Having heard the evidence, the Board concludes that, directionally, commencement of blowdown at this time would optimize energy conservation from the Kaybob South Beaverhill Lake A Pool provided that adequate provisions are in place to ensure that the high withdrawal rates* are sustained once blowdown commences. The Board believes that measures and facilities to sustain high withdrawals must be in place early, and therefore requires firm plans and commitments at this time. The Board is concerned that every effort be made to deplete those portions of the reservoir with remaining wet gas and that adequate producing and injection wells be available to accomplish these objectives.

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* For this purpose, "high withdrawal rates" means those approximating the rates demonstrated as optimum by the simulation models, specifically:
For Unit 2, Case 2 from Application 880332, and
For Unit 3, Case 6 from Application 880421.

Accordingly, the Board is prepared to grant approval of these applications, subject to each applicant establishing and submitting by 31 October 1989, firm plans describing how it will meet the following conditions.

3 CONDITIONS FOR APPROVAL

The Board requires that each applicant make a firm commitment to undertake the following:

3.1 Infill Wells

To drill all infill wells required to ensure maximum wet gas recovery within 6 months of the date of commencement of blowdown. Additionally, a firm commitment by each unit to drill the wells needed to achieve and sustain the high withdrawal rates, would be required as a condition of the approval.

3.2 Reinjection

That upon commencement of blowdown, reinjection of residue gas must be reduced to nil or minimal levels except where injection and cycling of gas is required to recover wet gas in accordance with unit and pool optimization plans.

3.3 Inlet Compression and Gas Lift

That sufficient additional inlet compression and gas lift equipment will be installed as required to maintain the high withdrawal rates from each unit.

3.4 Contingency Gas Withdrawal Plan

In addition to the foregoing means of maintaining high withdrawal rates, the Board requires that each applicant pursue every reasonable arrangement to ensure that high rates of withdrawal are sustained if and when contract sales are lowered on a seasonal basis. The Board will require that each applicant prepare a contingency gas withdrawal plan that shall include but not be limited to maintenance of the required high withdrawal rates through exchanges of contracts, gas storage and/or delivery of gas to enhanced recovery schemes.

3.5 Reporting Procedure

The Board requires that for the first 5 years of blowdown the applicants submit progress reports and meet with ERCB staff at 6-month intervals and annually thereafter to ensure adherence to the optimized depletion strategy. In concert with this, the applicants shall submit a monitoring program satisfactory to the Board as part of their depletion strategy.

After the Board receives the required plans regarding the above and is satisfied with all matters, an approval will be issued to permit blowdown. A final decision report concerning these applications will be issued at a later date setting out the reasons for the decision including those pertaining to the conditions outlined in this interim decision.

DATED at Calgary, Alberta, on 8 September 1989.

ENERGY RESOURCES CONSERVATION BOARD

N. A. Strom, P.Eng.
Vice Chairman

E. J. Morin, P.Eng.
Board Member

J. D. Dilay, P.Eng.
Acting Board Member

APPENDIX I

THOSE WHO PARTICIPATED AT THE HEARING

Participants and Representatives	Witnesses
Amoco Canada Resources Ltd. and Amoco Canada Petroleum Company Limited R. A. Neufeld V. Carson	R. Taylor F. Luciuk P. Swinton S. Mauger
Chevron Canada Resources J. Stein, Q.C. D. A. Rowbotham	C. Folden W. Da Sie D. Spencer W. Scott O. Gurpinar
Mobil Oil Canada A. S. Hollingworth	
Petro-Canada Inc. S. R. Miller	
B.P. Resources Canada Limited J. S. Rankin P. Harrison	
Unocal Resources Canada D. S. Paxman	
Consolidated Natural Gas Limited D. G. Davies	
Western Gas Marketing Limited D.I.D. McLean K. Martin	
Alberta & Southern Gas Co. Ltd. A. A. Fradsham	
Energy Resources Conservation Board staff A. Broughton D. Peet K. Hunt	

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

AMOCO CANADA RESOURCES LTD.
CHEVRON CANADA RESOURCES — Decision D 89-9
KAYBOB SOUTH BEAVERHILL LAKE A POOL — Applications 880332 and 880421

1 INTRODUCTION

1.1 Application

Amoco Canada Resources Ltd. (as successor in interest to Hudson's Bay Oil and Gas Company Limited (HBOG)) and Chevron Canada Resources applied separately for amendment of Approval No. 4044 to wind down dry gas cycling and proceed with maximum practical gas withdrawals so as to achieve rapid "blowdown" of the remaining gas reserves in Kaybob South Beaverhill Lake Gas Units No. 2 and 3, respectively. Both applications were supported by reservoir simulation forecasts which predicted that immediate commencement of blowdown would maximize overall hydrocarbon recovery. The studies indicated that continued entrapment of gas by active aquifer encroachment had reached a rate at which such losses were outstripping the potential benefits of the current operation of gas cycling with restricted net gas sales.

1.2 Pre-hearing Meeting

A pre-hearing meeting was held on 13 June 1989 to consider views regarding timing of the hearing and the scope of matters to be considered. Some participants argued that marketing arrangements could influence equity positions and conservation of resources, and that the hearing should consider all such matters. Others argued that the current applications were matters of conservation only, that other remedies were available to address equity, and that the hearing should be restricted to technical areas only. The Board decided to deal with the issue of optimum conservation, allowing participants to submit evidence respecting equity-related matters, but not necessarily institute remedies to these. (See Attachment 1, Memorandum of Decision.)

1.3 Hearing

The public hearing to consider the applications was held on 6 and 7 September 1989 with N. A. Strom, P.Eng., E. J. Morin, P.Eng., and J. D. Dilay, P.Eng. sitting. The participants are listed in Appendix 1.

At the opening of the hearing, all parties expressed a desire for an early decision by the Board as to whether it would be prepared to approve blowdown. With that objective, all agreed to set aside other concerns so that the hearing could focus on the technical aspects of achieving optimum energy resource conservation. Issues pertaining to marketing and transportation were tabled pending further negotiations between the operators and working interest owners with the provision that those matters could be heard at a later time.

1.4 Interim Decision

All parties expressed the need for an expeditious decision so as to facilitate negotiations concerning the unresolved marketing issues. An interim decision was released on 8 September 1989 specifying conditions to be met before a final approval would be issued. (See Attachment 2, Interim Decision D 89-9.)

2 BACKGROUND

The Kaybob South Beaverhill Lake A Pool, some 250 km northwest of Edmonton, is the largest gas pool discovered in Alberta, with an original gas-in-place (OGIP) presently estimated by the ERCB at 104.4×10^9 m^3 (see Table 1 for a reserves comparison between the applicants and the ERCB). After 20 years of production, the pool still ranks as one of the largest remaining marketable gas reserves in the province. The reservoir is contained in an elongated, dolomitized reef bank about 50 km in length, completely underlain by a large aquifer which adjoins several D-3 reservoirs. The pool is at a depth of about 3370 m and had an initial pressure of 31 720 kPa. The condensate-rich gas has a dewpoint of approximately 23 500 kPa, containing 17 mole per cent hydrogen sulphide with a C_5+ ratio of 452 m^3 per 10^6 m^3 of raw gas.

The Kaybob South Beaverhill Lake A Pool was discovered in 1961, with development occurring from north to south. Conservation strategy dictated that cycling operations be conducted to maximize condensate recovery before allowing blowdown to proceed. For this purpose three units were formed, Unit No. 1 in the northern segment, Unit No. 2 in the middle segment and Unit No. 3 in the southern portion. Unit No. 1 commenced cycling in November 1968, with the ERCB requirement that all residue gas be reinjected. Voidage replacement requirements were later reduced to 52 per cent (on a surface basis) in 1971. Under this mode of operation the reservoir pressure was allowed to gradually decline but still remain above the dewpoint to ensure maximum condensate recovery from cycling operations.

In 1969, a common approval was issued to cycle Units No. 2 (HBOG) and 3 (Chevron), at a required voidage replacement of 52 per cent (surface basis). Unit No. 2 commenced cycling in 1970, and Unit No. 3 commenced in 1972.

Water intrusion from the large adjoining aquifer has had the effect of partially sustaining reservoir pressure while at the same time causing entrapment of residual gas at high pressure, a detrimental effect on conservation. After 10 years of cycling, water intrusion into Unit No. 1 became the dominant concern respecting optimum gas recovery. On that consideration, in 1980, Unit No. 1 received conditional blowdown approval, subject to the Board being satisfied that sufficient marketing arrangements had been made to accommodate the increased gas sales rates. This condition was met in 1983, and Unit No. 1 commenced blowdown.

The outline of the pool and areas of high-producing wet-gas cuts are shown in the attached figure. The high wet-gas cut producing areas in Units No. 1 and 2 are generally characterized by thin pay, low productivity, and, in the north end of Unit No. 1, by very high producing water cuts which have led to well suspension. Table 2 summarizes the production performance of the three units during 1988. Pressures are fairly uniform except in Unit No. 3, in which there is a pressure sink in township 59, range 18, W5M in the same area in which there are high-producing wet-gas cuts. Operations are generally at a more mature stage in the north end of the pool, with lower producing wet-gas cuts and higher water-gas ratios.

3 ISSUES

With all participants agreeing to set aside issues pertaining to marketing and transportation, the issues relevant to this decision are

(1) the importance of initiating blowdown,
(2) concomitant means of optimizing recovery, and
(3) monitoring of the proposed schemes.

4 THE IMPORTANCE OF INITIATING BLOWDOWN

4.1 Views of Amoco

Amoco's model studies showed that immediate commencement of blowdown would result in maximum energy recovery from the pool and that delays in blowdown would cause commensurate reductions in ultimate recovery. The applicant said that it was possible, though highly unlikely, that the comparative advantages of immediate versus delayed blowdown could not be conclusively demonstrated within the range of uncertainty of its model.

As well, Amoco argued that economics would strongly favour immediate blowdown, though it did not submit economic analyses to support that view. It said that the percentage decrease in predicted energy recovery from delaying blowdown by several years was modest (see Table 3), but stated that, in absolute terms, this loss would be significant. Amoco agreed that there could be errors in the absolute level of recovery predicted, however, it held that errors would be transposed equally to the different forecasts, making these forecasts quite accurate for comparative purposes.

Amoco acknowledged that the OGIP value used in its study could be subject to uncertainty, and that adjustments to water influx, and not OGIP, were used to history match pressures. A study by Amoco examining sensitivity of optimum blowdown timing to OGIP confirmed that using a larger OGIP would cause water influx to be lower. However, Amoco contended that even with the lower water influx, recovery would be maximized by immediate blowdown.

To achieve a history match of observed water levels, Amoco lowered residual trapped gas saturations under water displacement to the range of 25 to 35 per cent, some 10 percentage points lower than the values observed from laboratory tests of core from the pool. Amoco believed the residual trapped gas saturations it used could have been reduced even further to obtain a better history match, but believed that it would have not been reasonable to do so in view of the core test saturations.

Amoco recognized that its use of a black oil-type simulation could introduce some uncertainty, but argued that errors would be negated in comparing relative differences between the forecast cases.

4.2 Views of Chevron

Chevron indicated that its model study clearly demonstrated the need for immediate blowdown in order to maximize energy recovery. Chevron did not view the small percentage differences between its forecasts (see Table 3) as an indication of uncertainty, given possible inaccuracies in its model. Rather, it stressed that the differences were substantial in absolute terms, and emphasized these converted to very large daily recovery losses that the Board must consider. Like Amoco, Chevron accepted there could be absolute errors in each of its forecasts, but contended these would be negated in making comparisons.

Chevron accepted the impossibility of obtaining a unique match of OGIP and water influx. However, it would not speculate what the effect of different OGIP would be on water influx or, in turn, the conclusions from its model. Chevron indicated that it had expended considerable effort in

obtaining the best geological description of the pool, and that its philosophy was to use its best resulting pressure history match model exclusively for determining the optimum depletion strategy.

To achieve a reasonable history match Chevron reduced residual trapped gas saturation to 20 per cent, a value about one-half the values obtained from core tests. But in considering all parameters (reservoir rock properties and volume, geology, pressure and production history, etc), Chevron saw little merit in attempting to reconcile residual trapped gas saturation as used in its model with those determined in laboratory tests.

Chevron used a black-oil model to simulate the reservoir's performance. It cited a study done by Intercomp in 1978 which indicated that errors introduced by using a black-oil model on this pool would be negligible in comparison with other effects, such as reservoir geometry and aquifer size. Chevron also argued that any error from this assumption would be negated when making comparisons of the merits of different depletion programs.

4.3 Views of the Board

While the Board generally agrees with the applicants' conclusions respecting the advantages of early and particularly sustained high blowdown rates, it does not fully accept the applicants' reservoir parameters. In particular, the Board believes it is possible that higher levels of residual trapped gas saturation and lower levels of water influx may exist, the effect being a need for continued emphasis on depletion of remaining condensate-rich areas at blowdown.

In Interim Decision D 89-9, the Board concluded that, directionally, early commencement of blowdown would optimize energy conservation. This assumes that high withdrawal rates during blowdown can be achieved and sustained. At the same time the Board believes that, with the uncertainties inherent in the model studies, it is not conclusive that immediate commencement of blowdown would result in any greater level of conservation than commencement some time within the next 2 years.

5 CONCOMITANT MEANS OF OPTIMIZING CONSERVATION

Recovery optimization relates primarily to the timing and sustainability of rapid blowdown of Units No. 2 and 3. For instance, reducing withdrawals because of reduced market sales could frustrate optimum conservation. Questions were therefore raised concerning what else could be done in concert with blowdown to optimize recovery.

5.1 Views of Amoco

Although there are at present restrictions to the amount of gas that can be removed from Unit No. 2, Amoco indicated that it looked forward to being able to market all residue gas. Amoco stated that its request to continue gas injection was a contingency measure due in part to the possibility that it would be unable to market all residue gas. Amoco agreed that a sudden cutback in net withdrawal rates after several years of production, or a general restriction to withdrawals during blowdown, would be detrimental to recovery.

Amoco stated it had no plans to relocate injection in order to maximize sweep of wet gas from the central part of Unit No. 2. It did, however, indicate that it had plans to drill four wells in that part of the unit, and that funds had been approved for one of them. In addition, Amoco indicated that funds had been authorized to drill a well adjacent to Unit No. 3 to mitigate gas migration.

Amoco expected initial gas sales rates to be about 2100 x 10^3 m^3/d, some 25 per cent lower than the levels in its forecasts. The reason for this was that the forecasts assumed additional inlet compression, which Amoco later concluded was uneconomic. Amoco affirmed that infill drilling and conversion of injectors to producers would be the prime means of increasing unit deliverability, augmented by conversion of water problem wells to gas lift. Amoco's operating strategy is to restrict the production rate of each well to a level below that at which water coning would be induced. Later, when water problems develop from general aquifer invasion, wells would be produced at the highest rates possible.

On the matter of sustaining high blowdown rates, Amoco investigated using gas storage to make up for periodic reductions in contract gas market sales, but determined that this would not be economic under present gas price conditions. Similarly, while Amoco felt that transfer of contracts from non-rate sensitive pools to sustain net withdrawal rates from Unit No. 2 would be possible, it believed this arrangement would be difficult for many owners to work out.

Amoco stated it preferred unconditional approval of its application, but indicated that conditional approval would be preferable to denial. It said it would have no major objection to withdrawal conditions provided they accounted for natural productivity decline. Amoco indicated that approval-in-principle would help its marketing negotiations while details of the approval were being worked out.

5.2 Views of Chevron

Chevron believed that both units could take advantage of expeditious approval because of available excess interruptible and non-interruptible transportation capacity. Chevron's request to continue gas injection was based primarily on the belief that wet-gas recovery could be increased from certain areas of the unit. Chevron did agree that, in general, withdrawal rates should be maximized, and that a sudden decrease in withdrawal rates after blowdown commencement would be detrimental to recovery.

There are two areas of high wet-gas cut in Unit No. 3 (see figure), of which Chevron investigated relocating injectors into the larger, northern area. Four candidates for injection relocation were evaluated using its reservoir simulator in four different scenarios, of which two showed a modest increase in overall recovery, but still had unfavourable economics. The smaller, southern high wet-gas cut area was not evaluated, but Chevron contended that this area would be swept prior to abandonment using the injectors it planned to retain. Chevron identified four infill drilling candidates, and although the stated purpose of these was to increase wet-gas production, none were centrally located in the high wet-gas producing areas. Furthermore, Chevron indicated that no firm commitment had been made to drill any of these wells.

Chevron indicated that it would expect initial gas sales to be about $7900 \times 10^3\ m^3/d$, very close to that indicated in Prediction Case 6, Chevron's expected production schedule. To initially sustain withdrawal rates, Chevron would convert all injection wells except the three in sections 1 and 2 of township 59, range 18, W5M. Compression would be brought on as shown in Prediction Case 6, and infill drilling evaluated as required. Chevron held that very few wells in Unit No. 3 exhibited what it termed rate-sensitive water production behaviour. Accordingly, it planned to limit production rates only in wells where water coning appeared to be developing.

Chevron expressed a high degree of confidence in being able to market its share of residue gas from Unit No. 3, and stated that any shortfall on its part could be overcome by disposition to miscible flood schemes. It acknowledged that it was speaking on its own behalf and not all Unit No. 3 owners, in that regard.

Like Amoco, Chevron preferred that any approval be unconditional, as it was concerned that conditions could adversely affect its ability to market gas. It did indicate that conditions would not be viewed as

overly onerous provided they allowed for reasonable deliverability decline. Chevron indicated it would welcome approval-in-principle while details of the approval were being worked out, inasmuch as that would allow it to proceed with firm marketing negotiations.

5.3 Views of the Board

Above all, the Board holds that a firm operating plan must be in place before blowdown commences. Firstly, the Board believes that the operating plans must provide for withdrawal under blowdown approximately equivalent to the preferred forecast schedules used in the justification for blowdown, specifically for Unit No. 2, Case 2 from the Amoco application, and for Unit No. 3, Case 6 from the Chevron application.

Secondly, the Board notes that the applicants have pointed out, correctly in the Board's view, that because the Kaybob South Beaverhill Lake A Pool is an extraordinarily large gas reservoir, even small percentage gains in recovery are very large in absolute terms. This argument is similarly valid when considering the remaining opportunities for condensate recovery from remaining condensate-rich areas of the pool. Also, the Board recognizes that continued injection may be beneficial in wells required to sweep gas from these areas.

To simultaneously meet both these broad objectives, the Board required in Interim Decision D 89-9 that firm commitments be made by the unit owners to the drilling of the needed infill wells, the cessation of reinjection except where required to maximize wet-gas recovery, the installation of additional inlet compression, the gas lift of water problem wells, and a contingency gas withdrawal plan for disposal of excess residue gas to ensure uninterrupted high blowdown rates. This contingency plan could include transfer of contracts from non-rate sensitive pools, and disposal to gas storage pools or miscible flood operations.

In Interim Decision D 89-9, the Board concluded that it would be prepared to approve both applications subject to the applicants putting in place firm operating plans so that the aforementioned conditions can be fulfilled.

6 MONITORING

6.1 Views of Amoco

Amoco confirmed that it would continue to run semi-annual tests of wet-gas cuts and water-gas ratios from producing wells, and annual bottom-hole pressure surveys in the unit. Amoco contended that monitoring of

the gas-water interface would be difficult, but agreed that a carefully considered logging program could give a reasonable indication of water influx. Amoco is willing to meet with Board staff to set up a gas-water interface monitoring program.

6.2 Views of Chevron

Chevron plans to continue with semi-annual tests of wet-gas cuts and water-gas ratios from producing wells, and will continue with its annual bottom-hole pressure survey to get a reasonable areal coverage of reservoir pressures. Chevron had not established a gas-water interface logging program, indicating that it planned to carry this out only when necessary to explain unusual increases in water production. Chevron contended that it had been diligent in monitoring gas-water contacts, and would continue to do so. It did agree that gas-water level monitoring was fundamentally important, and would meet with Board staff to set up a gas-water interface monitoring program.

6.3 Views of the Board

The Board considers a sound field monitoring program to be essential to achieving the objective of maximum recovery. In that regard every reasonable effort must be made to define the extent and rate of water influx into the pool, both on an overall and local basis. In Interim Decision D 89-9, the Board required that a reporting procedure satisfactory to the Board be submitted with the proposed depletion strategies. This reporting procedure would provide for blowdown progress reports accompanied by meetings with ERCB staff on a semi-annual basis for the first 5 years of blowdown, and annually thereafter.

7 DECISION

In Interim Decision D 89-9, the Board agreed that directionally, early blowdown would optimize energy conservation from the pool. The Board wishes to reiterate that it is essential that firm commitments be made to operate the blowdown schemes in a manner which will ensure maximum recovery. To this end, the approval of the applied-for schemes is conditional upon the terms of Interim Decision D 89-9 being met to the satisfaction of the Board.

DATED at Calgary, Alberta, on 4 December 1989.

ENERGY RESOURCES CONSERVATION BOARD

N. A. Strom, P.Eng.
Vice Chairman

E. J. Morin, P.Eng.
Board Member

J. D. Dilay, P.Eng.
Acting Board Member

APPENDIX 1

THOSE WHO PARTICIPATED AT THE HEARING

Participants and Representatives	Witnesses
Amoco Canada Resources Ltd. and	R. Taylor
Amoco Canada Petroleum Company Limited	F. Luciuk
R. A. Neufeld	P. Swinton
V. Carson	S. Mauger
Chevron Canada Resources	C. Folden
J. Stein, Q.C.	W. Da Sie
D. A. Rowbotham	D. Spencer
	W. Scott
	O. Gurpinar
Mobil Oil Canada	
A. S. Hollingworth	
Petro-Canada Inc.	
S. R. Miller	
BP Resources Canada Limited	
J. S. Rankin	
P. Harrison	
Unocal Resources Canada	
D. S. Paxman	
Consolidated Natural Gas Limited	
D. G. Davies	
Western Gas Marketing Limited	
D.I.D. McLean	
K. Martin	
Alberta & Southern Gas Co. Ltd.	
A. A. Fradsham	
Energy Resources Conservation Board staff	
A. Broughton	
D. Peet	
K. Hunt	

TABLE 1 KAYBOB SOUTH BEAVERHILL LAKE "A" POOL
ESTIMATED ORIGINAL GAS-IN-PLACE (10^9 m^3)

AMOCO CANADA RESOURCES LTD.	102.7
CHEVRON CANADA RESOURCES	109.1
ENERGY RESOURCES CONSERVATON BOARD	104.4

TABLE 2 KAYBOB SOUTH BEAVERHILL LAKE "A" POOL
1988 PRODUCTION PERFORMANCE

	Avg Daily Raw Gas Production $10^3m^3/d$	Avg Daily Dry Gas Injection $10^3m^3/d$	Plant Yield C_5+ $m^3/10^6m^3$	WGR $m^3/10^3m^3$
Unit No 1*	1881.2	34	221.3	1.013
Unit No 2	1953.3	820	120.2	0.468
Unit No 3	8064.0	5111	125.3	0.112

* 87-07-01 to 88-06-30 performance period

TABLE 3 PERCENTAGE DECREASE IN PREDICTED ENERGY
RECOVERY FROM DELAYING BLOWDOWN FOR 2 YEARS

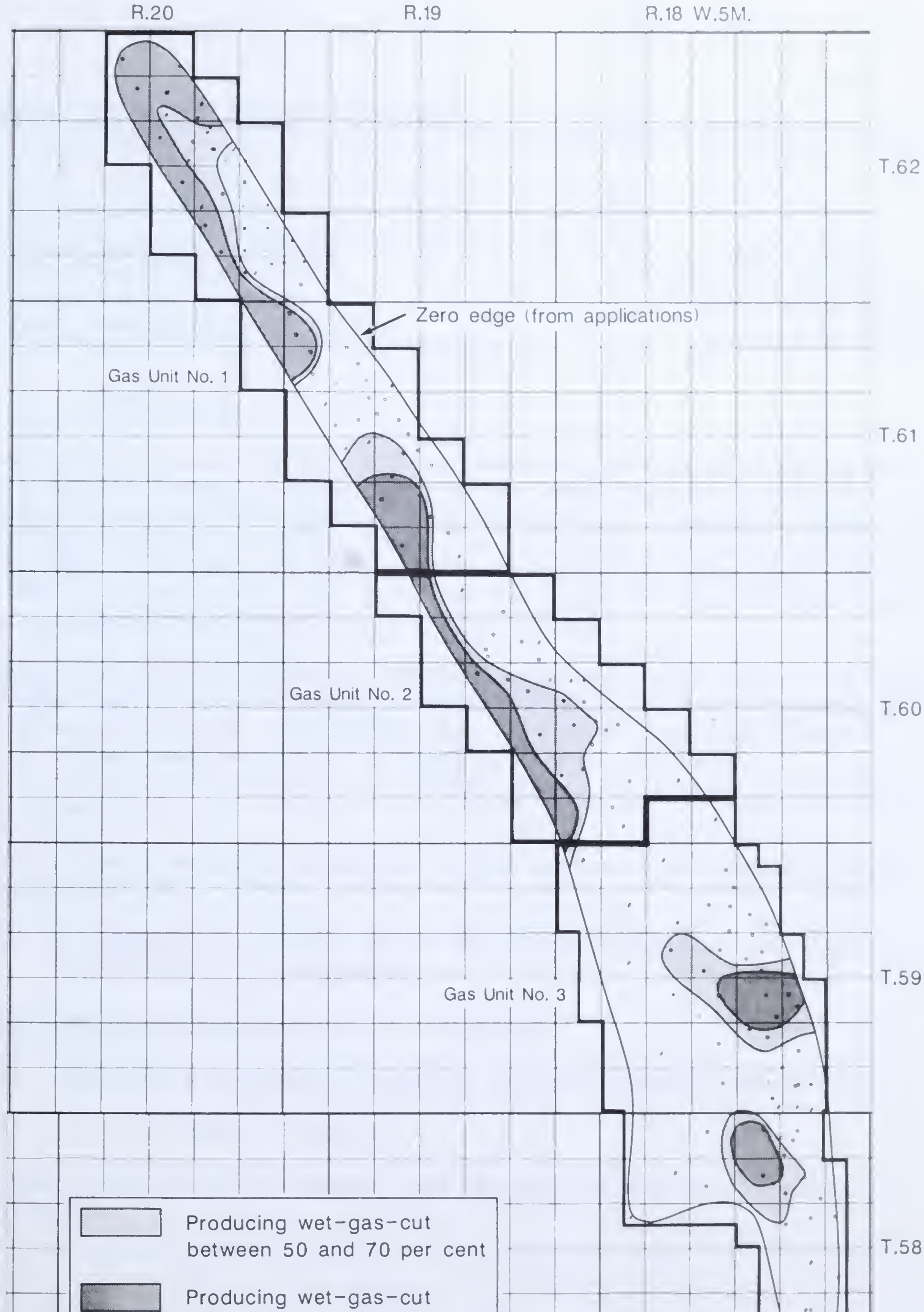
	Unit 2	Unit 3	Total Pool[b]
HBOG*	- 0.56	- 1.18	- 0.48
CHEVRON#	+ 3.46[a]	- 1.00	- 0.14
	+ 2.28[a]	- 2.79	- 1.46

* From Exhibit J.6 - 6 September, 1989 Board Hearing

\# From Exhibit J.8 - 6 September, 1989 Board Hearing (two sets of predictions were compared)

a Indicates a net energy gain in Unit No. 2

b Total pool includes Units No. 1, 2, and 3



KAYBOB SOUTH BEAVERHILL LAKE A POOL

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

HEARING DATE AND PROCEDURES
AMOCO CANADA RESOURCES LTD.
CHEVRON CANADA RESOURCES
KAYBOB SOUTH BEAVERHILL LAKE A

Memorandum of Decision
Application 880332
Application 880421

1 INTRODUCTION

Amoco Canada Resources Ltd. (as successor in interest to Hudson's Bay Oil and Gas Company Limited) and Chevron Canada Resources applied to the Energy Resources Conservation Board separately for amendment of Approval No. 4044 to curtail dry gas cycling and increase gas sales (hereinafter referred to as blowdown) in Kaybob South Beaverhill Lake Gas Units No. 2 and 3, respectively. The Board decided these two applications should be considered concurrently at a public hearing.

Because of differing views expressed to the Board with respect to timing of the hearing and the issues to be considered, the Board convened a pre-hearing meeting. The meeting was held on 13 June 1989 before a Board panel comprised of G. J. DeSorcy, P.Eng. (Chairman), N. A. Strom, P.Eng., and J. P. Prince, Ph.D. The attendees are listed in Appendix I.

The following matters, as set out in the notice of the meeting, were considered:

(a) the appropriate timing of the hearing and deadlines for filing of interventions and responses,

(b) the scope of matters to be considered,

(c) any special procedures needed to facilitate participation, and

(d) any other matters suggested.

A brief outline of each matter, and the Board's decision on each, follows.

ATTACHMENT

2 TIMING OF THE HEARING AND DEADLINES

There was a reasonable consensus for a hearing date in early September 1989. Accordingly, the Board has set the hearing date for 6 September 1989. There was also reasonable agreement on filing deadlines for interventions and responses, for which the Board has set 7 August 1989 and 28 August 1989, respectively.

3 SCOPE OF MATTERS TO BE CONSIDERED

Conservation of resources (as the technical justification for blowdown) was generally accepted as an issue for the hearing.

A number of ancillary, equity-related issues were raised, including inter-unit drainage, the need for a gas marketing agreement, and availability of gas transportation. Views differed on whether or not these matters should be considered at the hearing.

The Board has decided to hear submissions regarding any of these matters, in order to determine their relevance to the decision. In so doing, the Board would not necessarily be bound to institute remedies to these ancillary issues.

4 SPECIAL PROCEDURES NEEDED TO FACILITATE PARTICIPATION

Amoco proposed, and others agreed, that the Board should, in effect, follow its standard procedures for hearing applications concurrently. These procedures are intended to avoid duplication and minimize the number of separate appearances by each applicant and intervener.

The Board expects to follow these standard procedures, but with the option to make adjustments closer to the hearing date if warranted by a change in circumstances. All registered participants will be kept advised of any changes to the hearing procedure.

5 OTHER MATTERS

Amoco requested leave to apply for wellbore and well-site modifications and pipeline permits necessary for blowdown, prior to blowdown approval, on the basis that this would be at Amoco's own risk.

The Board is prepared to consider applications for these kinds of facilities in the normal manner on their own individual merits, and prior to the blowdown applications. The Board will, however, give other operators in the pool an opportunity to object. Should these applications be approved, the approval would emphasize that Amoco proceeds entirely at its own risk, and that the Board would have no consideration for Amoco's investment in reaching a decision on the blowdown application.

DATED at Calgary, Alberta, on 21 June 1989.

ENERGY RESOURCES CONSERVATION BOARD

G J DeSorcy

G. J. DeSorcy, P.Eng.
Chairman

N. A. Strom, P.Eng.
Vice Chairman

J. P. Prince

J. P. Prince, Ph.D.
Board Member

Mr. Strom was not available to sign this decision, but is in agreement with it.

APPENDIX I

THOSE WHO APPEARED AT THE PRE-HEARING MEETING

Participants	Representatives
Chevron Canada Resources	D. Rowbotham J. Stein
Amoco Canada Resources Ltd. and Amoco Canada Petroleum Company Ltd.	R. Neufeld V. Carson
Mobil Oil Canada	A. Hollingworth L. Anderson
Petro-Canada Inc.	S. Miller W. Leach
BP Resources Canada Limited	J. Rankin P. Harrison
Western Gas Marketing Limited	J. Maher K. Martin K. Rawson
Consolidated Natural Gas Limited	P. Leier P. McMillan
Energy Resources Conservation Board staff	A. Broughton H. Keushnig K. Hunt D. Peet

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

AMOCO CANADA RESOURCES LTD.
CHEVRON CANADA RESOURCES
KAYBOB SOUTH BEAVERHILL LAKE A

Interim Decision D 89-9
Application 880332
Application 880421

1 INTRODUCTION

Amoco Canada Resources Ltd. (as successor in interest to Hudson's Bay Oil and Gas Company Limited) and Chevron Canada Resources applied separately for amendment of Approval No. 4044 to curtail dry gas cycling and increase gas sales (hereinafter referred to as blowdown) in Kaybob South Beaverhill Lake Gas Units No. 2 and 3, respectively. The applications were considered concurrently at a public hearing held on 6 and 7 September 1989 with N. A. Strom, P.Eng., E. J. Morin, P.Eng., and J. D. Dilay, P.Eng. (acting Board Member) sitting. The participants are listed in Appendix I.

At the opening of the hearing, all parties agreed that only issues pertaining to the technical aspects of the applications, primarily focusing on energy conservation, would be heard at this time. Issues pertaining to transportation and marketing would be tabled pending further negotiations among the working interest owners and, only if necessary heard at a later date. Both applicants expressed the need for an expeditious decision on the applications and hence this interim decision report is being issued.

2 INTERIM DECISION

Having heard the evidence, the Board concludes that, directionally, commencement of blowdown at this time would optimize energy conservation from the Kaybob South Beaverhill Lake A Pool provided that adequate provisions are in place to ensure that the high withdrawal rates* are sustained once blowdown commences. The Board believes that measures and facilities to sustain high withdrawals must be in place early, and therefore requires firm plans and commitments at this time. The Board is concerned that every effort be made to deplete those portions of the reservoir with remaining wet gas and that adequate producing and injection wells be available to accomplish these objectives.

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* For this purpose, "high withdrawal rates" means those approximating the rates demonstrated as optimum by the simulation models, specifically:
For Unit 2, Case 2 from Application 880332, and
For Unit 3, Case 6 from Application 880421.

ATTACHMENT

Accordingly, the Board is prepared to grant approval of these applications, subject to each applicant establishing and submitting by 31 October 1989, firm plans describing how it will meet the following conditions.

3 CONDITIONS FOR APPROVAL

The Board requires that each applicant make a firm commitment to undertake the following:

3.1 Infill Wells

To drill all infill wells required to ensure maximum wet gas recovery within 6 months of the date of commencement of blowdown. Additionally, a firm commitment by each unit to drill the wells needed to achieve and sustain the high withdrawal rates, would be required as a condition of the approval.

3.2 Reinjection

That upon commencement of blowdown, reinjection of residue gas must be reduced to nil or minimal levels except where injection and cycling of gas is required to recover wet gas in accordance with unit and pool optimization plans.

3.3 Inlet Compression and Gas Lift

That sufficient additional inlet compression and gas lift equipment will be installed as required to maintain the high withdrawal rates from each unit.

3.4 Contingency Gas Withdrawal Plan

In addition to the foregoing means of maintaining high withdrawal rates, the Board requires that each applicant pursue every reasonable arrangement to ensure that high rates of withdrawal are sustained if and when contract sales are lowered on a seasonal basis. The Board will require that each applicant prepare a contingency gas withdrawal plan that shall include but not be limited to maintenance of the required high withdrawal rates through exchanges of contracts, gas storage and/or delivery of gas to enhanced recovery schemes.

3.5 Reporting Procedure

The Board requires that for the first 5 years of blowdown the applicants submit progress reports and meet with ERCB staff at 6-month intervals and annually thereafter to ensure adherence to the optimized depletion strategy. In concert with this, the applicants shall submit a monitoring program satisfactory to the Board as part of their depletion strategy.

After the Board receives the required plans regarding the above and is satisfied with all matters, an approval will be issued to permit blowdown. A final decision report concerning these applications will be issued at a later date setting out the reasons for the decision including those pertaining to the conditions outlined in this interim decision.

DATED at Calgary, Alberta, on 8 September 1989.

ENERGY RESOURCES CONSERVATION BOARD

N. A. Strom, P.Eng.
Vice Chairman

E. J. Morin, P.Eng.
Board Member

J. D. Dilay, P.Eng.
Acting Board Member

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

GANNON BROS. ENERGY LTD.
APPLICATION FOR A WELL LICENCE
EWING LAKE FIELD

Decision D 89-10
Application 891207

1 INTRODUCTION

1.1 Application

Gannon Bros. Energy Ltd. (Gannon Bros.) applied in accordance with section 2.020 of the Oil and Gas Conservation Regulations for a licence to drill a well in legal subdivision 2 of section 25, township 37, range 21, west of the 4th meridian. The proposed well, to be known as GANNON EWING LAKE 2-25-37-21 (the 2-25 well), would be for the purpose of obtaining oil production from the Nisku Formation.

1.2 Intervention

An intervention opposing the application was filed by Bernard and Marie Van Straten, the registered owners of the southeast quarter of section 25, township 37, range 21, west of the 4th meridian.

1.3 Hearing

A public hearing of the application was held on 26 September 1989 in Stettler, Alberta, before Board Member F. J. Mink, P.Eng. and Acting Board Members T. F. Homeniuk, P.Eng. and W. G. Remmer, P.Eng.

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Gannon Bros. Energy Ltd. (Gannon Bros.) F. G. Gannon	
Bernard and Marie Van Straten K. M. Sproule	Bernard Van Straten
Energy Resources Conservation Board Staff N. F. Lord, C.E.T.	

Prior to commencement of the hearing, Gannon Bros. challenged the authority of the Energy Resources Conservation Board (the Board) to hold the hearing and continue with the proceedings. Gannon Bros. argued that the evidence did not show the proposed application would have an adverse effect on the intervener since the Van Stratens would be fully compensated for the intrusion. Gannon Bros. further argued that any proposed changes to the existing access road are not within the jurisdiction of the Board. The Board ruled that pursuant to section 29 of the Energy Resources Conservation Act it had the authority to conduct the hearing to allow parties who may be directly and adversely affected by an application a reasonable opportunity to present evidence and be heard before the Board. The Board then continued with the hearing and consideration of the submissions.

At the conclusion of the hearing, the Board, its staff, the applicant, and the intervener visited the area of application in order that the participants could draw the Board's attention to any on site particulars they believed were germane to their respective positions.

2 ISSUES

The Board considers the issues with respect to the application to be

- the need for the well,
- the location of the well,
- the access route to the well, and
- the impact of the well site and access road.

3 CONSIDERATION OF THE APPLICATION

3.1 Views of the Applicant

Gannon Bros. submitted that the well is needed to capture potential reserves which may not be recovered by an existing well located at 7-25-37-21 W4M (7-25) in the drilling spacing unit (DSU). Gannon Bros. submitted that the 7-25 well is currently producing significant volumes of water and recompleting the 7-25 well would not enhance its productivity. If the 2-25 well is successful, the applicant would shut the 7-25 well in, recognizing that only one well may be produced in the DSU. The 7-25 well could possibly be used for enhanced recovery at a later date.

Gannon Bros. submitted that the proposed location of the 2-25 well was determined by geological interpretation and geophysical data which suggested the proposed well could be expected to encounter a Nisku reef structurally higher than the offset 7-25 well. It stated that the selected location is geologically the optimum in the DSU. It is

expected to encounter a greater pay thickness than that found in the 7-25 well and also avoid the production of large volumes of water. Gannon Bros. submitted a geophysical report outlining the expected pool.

Gannon Bros. stated that to access the 2-25 well site it proposed to utilize an existing access road which led to the 7-25 well (see attached figure). In its opinion this was the most practical way to access the proposed site, considering that the road already exists.

With respect to the impact of the proposed well and access road on agricultural activities, Gannon Bros. submitted that it did not believe that any adverse impact would result which would prevent it from proceeding with the well. It argued that the actual well site would require only a minimum amount of additional land and, given that agricultural activities on the land surface had ended for the year, it is an opportune time to proceed with drilling activities.

3.2 Views of the Intervener

Mr. Van Straten stated that he did not question the need for the well nor the right of Gannon Bros. to attempt to recover any reserves which may underlie the DSU.

Mr. Van Straten also stated that he did not dispute the basis for locating the well site as proposed. He did, however, submit that the southern portion of the existing access road should be shifted to the east and realigned in a true north-south direction (see attached figure). This would, in his opinion, reduce the combined impact of the proposed well site and access road on his agricultural activities. Mr. Van Straten submitted that the current road, coupled with a well site, would mean increased turns required to farm around the well site, resulting in areas of land that could not be cultivated with large equipment. He argued that his proposed realignment would reduce these negative impacts by decreasing the number of turns required to farm around the proposed facilities. Further, the realignment would allow large machinery easier access to corner areas created by the existing access road. In his view, reclamation of the existing road would be a simple matter and would not affect the productivity of the land.

3.3 Views of the Board

The Board accepts the need for the 2-25 well. The Board notes, however, that if a well licence were to be issued for the 2-25 well, it would be conditioned such that only one well may produce in the DSU. If in fact the 2-25 well were successful, the Board would expect Gannon Bros. to submit a report within a 1-year period setting out the proposed abandonment procedures or proposed utilization of the shut-in 7-25 well.

The Board also accepts the geological and geophysical bases on which Gannon Bros. selected the well site location. Respecting the impact of the well site itself, the Board notes that the well site location was not disputed by Mr. Van Straten.

The Board has considered Mr. Van Straten's suggestion that the existing access road should be realigned. It notes that the road has existed for some period of time as a means of access to the 7-25 well and is intended to be used by Gannon Bros. as a means of access to the proposed 2-25 well. The Board is satisfied that use of the road to access the 2-25 well would not result in any new impacts beyond those which already exist. Furthermore, after viewing the existing road, the Board is not convinced that relocating it, as suggested by Mr. Van Straten, would reduce the current impacts on farming. It is evident that farming operations take place within a reasonable proximity to the road on the section in question. Relocation of the road would involve an additional expense without any appreciable offsetting benefit.

4 DECISION

After carefully considering the evidence, the Board is satisfied that there is a need for the well. It does not believe that the negative impacts associated with the proposed well and use of the existing access road would be so great that the Board should deny the application. Accordingly, the application is approved and a well licence will be issued in due course.

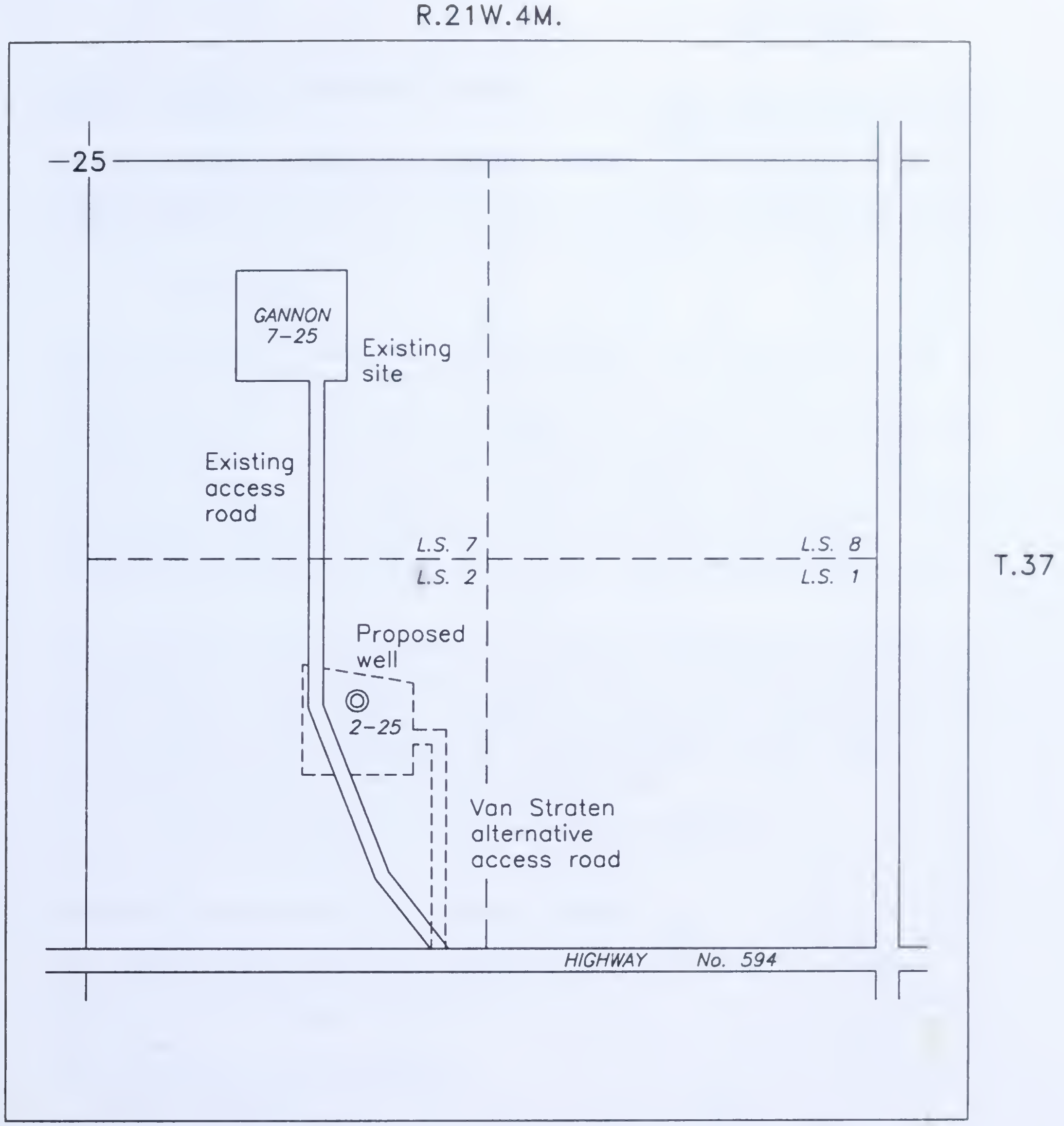
DATED at Calgary, Alberta, on 26 October 1989.

ENERGY RESOURCES CONSERVATION BOARD

P. J. Mink, P.Eng.
Board Member

T. F. Homeniuk, P.Eng.
Acting Board Member

W. G. Remmer, P.Eng.
Acting Board Member



PROPOSED WELL LOCATION
Application No. 891207
Gannon Ewing Lake 2-25-37-21

D 89-10
ERCB

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

CANADIAN WESTERN NATURAL GAS COMPANY LIMITED
APPLICATION FOR A PIPELINE PERMIT
MAGRATH AREA

Memorandum of Decision
Pre-hearing Meeting
Application No. 891549

1 INTRODUCTION

Canadian Western Natural Gas Company Limited (CWNG) applied to the Energy Resources Conservation Board (the Board) for a permit to construct approximately 12 kilometres of 114.3-millimetre outside diameter pipeline and related facilities to transport natural gas from an existing meter station located in legal subdivision (Lsd) 4 of section 34, township 5, range 22, west of the 4th meridian, to an existing pipeline in Lsd 13-21-6-21 W4M. The Board decided that the application should be considered at a public hearing, and that a pre-hearing meeting should be held to hear representations respecting certain aspects of the public hearing.

The pre-hearing meeting, which was originally scheduled to be held on 7 November 1989, was adjourned at the request of Pacific Cassiar Ltd. (PCL), and was held in the El Rancho Motor Hotel in Lethbridge, Alberta, on 21 November 1989, before a division of the Board comprised of J. P. Prince, Ph.D. (Chairman), N. G. Berndtsson, P.Eng., and C. A. Langlo, P.Geol. (Acting Board Members).

2 THOSE WHO APPEARED AT THE PRE-HEARING MEETING

Canadian Western Natural Gas Company Limited	B. K. O'Ferrall J.E.E. Lowe
Gulf Canada Resources Limited (Gulf)	D. Gandar
Mohawk Oil Company Limited (Mohawk)	D. A. Holgate
Pacific Cassiar Limited (PCL)	Steve Vavra
John Mehew	R. Dodic
John Balderson, David Balderson and Ken Balderson	K. Balderson
Rampage Holdings Limited	Stan Vavra
Roy Schulze and Rita Lambert	R. Schulze and R. Lambert
Edgar Lawrence Hill	R. Bissett
Indian Oil and Gas Canada (IOGC)	L. Wong

Energy Resources Conservation Board staff
- A. A. Broughton
- S. C. Lee
- M. P. Vandenbeld
- K. Fisher

3 MATTERS CONSIDERED AT THE PRE-HEARING MEETING

The following items as set out in the Notice of Pre-hearing Meeting/Notice of Hearing and the Notice of Re-scheduling of Pre-hearing Meeting were considered:

- o the scope of matters to be considered at the public hearing of the application,

- o any special procedures needed to facilitate participation in the public hearing, and

- o any other matters suggested.

The purpose of the pre-hearing meeting was to identify the issues and to provide an opportunity for participants to comment on their relevance to the application under consideration.

3.1 Views of Pre-hearing Meeting Participants

3.1.1 Scope of The Matters to Be Considered at the Public Hearing

The applicant, CWNG, as well as Gulf and Mohawk, expressed the view that the scope of the hearing should be confined to those issues normally dealt with by the Board when assessing a pipeline permit application, namely, the need for, the routing of, and the potential surface impacts of the pipeline.

Gulf expressed the view that the scope of the hearing should exclude consideration of issues such as drainage and pipeline costs. CWNG and Mohawk agreed that although issues of oil and gas development are under the Board's jurisdiction through the oil and gas conservation legislation, these issues are not relevant to a pipeline hearing.

PCL expressed the view that the Board, in considering matters placed before it under the Pipeline Act, is also responsible through its legislation to consider matters which fall within the mandate of the Oil and Gas Conservation Act. PCL suggested that in evaluating the economic, orderly, and efficient development of pipeline facilities, it may be necessary for the Board to also look at the orderly and efficient development of oil and gas pools, including the equity relationships created by new or increased production rates, when those issues are related.

Rampage Holdings Limited, Mr. Roy Schulze, and Ms. Rita Lambert stated that their position is the same as that expressed by PCL.

Mr. John Mehew agreed with PCL's position on scope and also raised surface concerns related to his farming operations.

Mr. Ken Balderson stated that the entire area of gas production should be unitized but did not comment on the scope of the hearing.

Mr. Ted Hill stated that his concerns related to control of pollution and conservation of the environment in the development and operation of pipeline facilities.

IOGC expressed the view that its land holdings should be unitized and stated that it may wish to make a presentation at the hearing.

3.1.2 Any Special Procedures Needed to Facilitate Participation at the Hearing

The participants at the pre-hearing meeting did not see any need for any special hearing procedures.

3.1.3 Any Other Matters Suggested

CWNG, Gulf, and Mohawk stressed that the timing of the public hearing was of considerable importance to them because even a brief delay could result in construction being delayed for 1 year since the proposed pipeline is within an irrigation district.

No additional matters were raised by the pre-hearing meeting participants.

4 VIEWS OF BOARD

The Board concluded that the issues relevant to the pipeline application include

- o the need for the pipeline,
- o the routing and potential surface impacts of the pipeline, and
- o other potential environmental concerns.

The Board considers the question of need for a pipeline to be a very broad issue which would include consideration of whether the proposed facilities represent orderly, economic, and efficient development in the public interest.

In considering the need for the pipeline, the Board is prepared to hear any evidence that can be shown to be relevant to the pipeline including such matters as contractual requirements, the pipeline capacity, and the source of production to fill that capacity. The latter could include evidence on pool gas reserves and appropriate pool production rates.

The Board cautions all participants that it does not believe that issues related to possible drainage and overall pool development can be resolved through a decision on a pipeline permit application.

The Board recognizes that competitive operations may result in equity concerns as identified at the pre-hearing meeting. This is not a unique situation, as it can and does occur in many gas pools. The Board prefers that such problems be settled through negotiation among affected parties. In the event that negotiation is unsuccessful there are circumstances under which the Board's legislation allows application to be made to resolve the issues. However, the onus in advancing equity-related matters rests with the affected parties to demonstrate that negotiation has been attempted and that a lack of opportunity to obtain a fair share of production from a pool exists. The mechanisms available to deal with equity-related issues would include the rateable take or common carrier provisions of the Oil and Gas Conservation Act.

The applied-for pipeline, if approved, may or may not lead to concern regarding equitable production. If it does, the Board assumes the applicant understands that any action necessary to ensure equitable development of the pool would not be limited by the existence of the pipeline.

5 HEARING

The hearing of Application No. 891549 will proceed at 9:00 a.m. on 5 December 1989 as outlined in the Notice of Hearing.

DATED at Calgary, Alberta, on 24 November 1989.

ENERGY RESOURCES CONSERVATION BOARD

J. P. Prince

J. P. Prince, Ph.D.
Board Member

N. G. Berndtsson, P.Eng.
Acting Board Member

C. A. Langlo

C. A. Langlo, P.Geol.
Acting Board Member

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

APPLICATION BY CANADIAN WESTERN NATURAL GAS COMPANY LIMITED
FOR A PERMIT TO CONSTRUCT A PIPELINE
TO TRANSPORT NATURAL GAS
IN THE MAGRATH AREA

Decision D 89-11
Application 891549

1 INTRODUCTION

1.1 Background Information

Pursuant to Part 4 of the Pipeline Act, Canadian Western Natural Gas Company Limited (CWNG) submitted Application 891549 for a permit to construct approximately 12 kilometres (km) of pipeline loop, 114.3 millimetres (mm) in outside diameter, to transport natural gas in the Magrath area. The route applied for is shown in the attached figure. Because of complexities of the issues raised by the potential interveners, a pre-hearing meeting was held in Lethbridge, Alberta, on 21 November 1989 to identify issues appropriate to the public hearing. Following the pre-hearing meeting, the Board concluded that the issues related to the application include the need for the pipeline, the routing and potential surface impacts of the pipeline, and other potential environmental concerns. The Board cautioned all participants that issues related to possible drainage and to overall development of the Blood Bow Island A Pool (the A Pool) or any other pool cannot be resolved through a decision on a pipeline application.

The A Pool is a small, non-associated gas pool currently defined by the Board as including nine sections as shown in the figure. Pacific Cassiar Limited (PCL) is currently producing one well in the pool through a pipeline extending directly east from the well towards an existing CWNG pipeline. The remaining wells in the pool are either owned or operated by Gulf Canada Resources Limited and Mohawk Oil Company Limited. Gas from the latter wells is flowing south from the A Pool and enters the CWNG pipeline near Magrath, Alberta, as depicted in the figure.

1.2 Hearing

The application was considered at a public hearing in Lethbridge, Alberta, on 5 December 1989, with Board Member J. P. Prince, Ph.D., and Acting Board Members N. G. Berndtsson, P.Eng., and C. A. Langlo, P.Geol., sitting.

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Canadian Western Natural Gas Company Limited B. K. O' Ferrall J.E.E. Lowe	T. Haddow, P.Eng. B. Broderick, P.Eng. P. Rettallack, P.Eng. R. A. Berrien, P.Ag., A.R.A. of R. A. Berrien Associates (Rural) Ltd.
Gulf Canada Resources Limited (Gulf) D. Gandar	A. L. Crawley B. Flynn, P.Eng. K. Hadley
Mohawk Oil Company Limited (Mohawk) D. A. Holgate	C. A. Weston
Pacific Cassiar Limited (PCL) Steve Vavra	Steve Vavra, P.Eng. E. Tetreau, P.Eng.
John Mehew R. Dodic	John Mehew
Edgar Lawrence Hill R. Bissett	Alice Birch Edgar Lawrence Hill
Rampage Holdings Limited Stan Vavra	
Roy Schulze and Rita Lambert Roy Schulze	
Indian Oil and Gas Canada (IOGC) L. Wong, P.Eng.	
Energy Resources Conservation Board staff A. A. Broughton S. C. Lee, P.Eng. M. P. Vandenbeld, C.E.T. K. Fisher, C.E.T.	

2 ISSUES

As summarized in the Memorandum of Decision dated 24 November 1989 for Application 891549, the Board considers that the issues relevant to the application are

- the need for the pipeline;
- the routing and potential surface impacts of the pipeline; and
- other potential environmental concerns.

3 NEED FOR THE PIPELINE

3.1 Views of the Applicant

CWNG stated that it requires the proposed pipeline loop to provide an additional capacity of 85 x 10^3 cubic metres per day (m^3/d) to satisfy an agreement between itself and Gulf. The purpose of the pipeline is to transport natural gas produced from the A Pool and sold by Gulf, thus satisfying Gulf's need as a commercial owner of natural resources to develop and market its gas.

CWNG evaluated three options to satisfy this agreement - namely, to increase the maximum operating pressure (M.O.P.) of the existing pipeline and thereby gain more capacity; to loop pipeline from the Gulf/Magrath meter station (the Magrath Station) through the Welling Wye to the East Mainline[1] on the CWNG system; and to loop a pipeline between the Magrath Station and the Welling Wye as proposed. CWNG rejected the first option because of the age of the pipeline and the potential for problems associated with raising the M.O.P. of the pipeline. The pipeline would also have to be isolated from the surrounding pipelines which operate at lower pressures. Failure of the pipeline during an attempted M.O.P. upgrade would affect approximately 620 CWNG customers. The second option was rejected as uneconomic. CWNG views the last option as the optimal configuration to add transportation capacity while sustaining an acceptable pressure drop.

CWNG stated that the proposed pipeline, if approved, would enable the use of currently untapped pipeline capacity between the Welling Wye and the East Mainline, would help secure gas supply in southern districts such as Cardston at no additional cost to the Cardston customers, and would result in better opportunities for gas marketing including interruptible sales, thereby encouraging exploration and resource development in the area.

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1 The East Mainline is the line north of Lethbridge running east and west some 33 km north of the Welling Wye.

3.2 Views of the Interveners

PCL argued that the gas reserves of the A Pool are currently being produced in an orderly and efficient manner, and that accelerated production as proposed by Gulf would not benefit anyone other than the applicant.

Gulf, as operator of Blood-Magrath Unit No. 1 (the Magrath Unit), echoed CWNG's comments with respect to the need for added pipeline capacity and limitations on existing lines. Gulf argued that the A Pool has been produced competitively because differences in geological interpretations between Gulf and PCL have precluded a unitization agreement. Consequently, Gulf stated that Gulf/Mohawk's reserves in the Magrath Unit are being drained by PCL. Gulf stated that it has secured a Pan-Alberta gas contract, dated 3 November 1980, with a maximum of 280.6×10^3 m^3/d and a minimum of 211.0×10^3 m^3/d; however, despite Gulf's ability to meet the contract's maximum, Pan-Alberta has been restricted to taking only 141×10^3 m^3/d because of the limited existing pipeline capacities.

Gulf claimed that the lost sales would become significant in the 1989-90 contract year. It requires additional transportation capacity to allow it to produce above 141×10^3 m^3/d to fulfil its contractual opportunities.

PCL argued that the proposed pipeline would not increase ultimate recovery from the A Pool and that Gulf's wells in the pool could only produce at rates required to fill the requested pipeline capacity for 3 to 4 years; hence the line would be an economic waste. Gulf responded that its reserves and forecasts of deliverability indicate that Gulf/Mohawk's production from the A Pool will decline only to the current restricted rate of 141×10^3 m^3/d in the period 1995-1996 and that its facility can produce at full nomination of 211×10^3 m^3/d for at least 4 to 5 years. Gulf maintained that with increased production, the pool will last until late 1997, as compared to late 1998 under current production rates, and that the increased production will not adversely affect the ultimate recovery from the pool. Mohawk, a joint operator of the Pan-Alberta gas contract, argued that the proposed pipeline encourages further development in the area. Recent drilling, as well as plans for future drilling, point to more gas reserves that will take up any future pipeline capacity in whatever contractual arrangements can be obtained in the future.

PCL, however, stated that future development should have no bearing, since the pipeline is proposed to meet only Gulf's present contract with Pan-Alberta.

In response to PCL's concern that the proposed line provides no extra capacity for other operators in the region, since CWNG's existing system is limited by a bottleneck to the north, Gulf stated that, although future upgrading may be necessary, the CWNG system now has sufficient spare capacity to accommodate Gulf's additional volume.

3.3 Views of the Board

The Board considers the question of need for a pipeline a very broad issue - one that requires deliberation as to whether the proposed facilities represent orderly, economic, and efficient development in the public interest. Such matters as contractual requirements, pipeline capacity, production to fill that capacity, evidence of the extent of gas pool reserves, and appropriate pool production rates fall within the broad issue.

The Board also accepts the evidence of CWNG and Gulf that increased capacity to transport gas is needed for Gulf to develop and market its reserves of natural gas in the region.

The Board concurs with CWNG that its proposal to loop the existing transmission line from the Magrath Station to the Welling Wye is the best option, of those considered at the hearing, to satisfy the need for added capacity. This will enable Gulf to meet its minimum commitments of 211 x 10^3 m^3/d under its contract with Pan-Alberta. The Board is satisfied that sufficient capacity exists within the A Pool to fill the minimum contracted volumes required by Gulf. If Gulf, through its arrangement with CWNG, is prepared to invest in a pipeline to transport gas from the area, the Board would not deny it that opportunity unless there were related adverse effects sufficient to justify such denial. The Board also notes that some potential for development of additional gas reserves in the area was demonstrated. Should that potential be realized, owners of those reserves could use any spare capacity that might develop in the transportation system in future.

The 114.3-mm loop, combined with the existing older line of the same size, would result in some extra capacity in the immediate future and would also permit present operation at lower line pressures. Installing a loop of smaller diameter would not appreciably alter the economics of the project.

The Board concludes that on the basis of evidence supplied at the hearing, the proposed pipeline is needed to transport gas reserves from the Blood Magrath area to gas consumers.

4 ROUTING AND POTENTIAL SURFACE IMPACTS OF THE PIPELINE

4.1 Views of the Applicant

CWNG stated that in order to minimize concerns of farmers and landowners and to facilitate the tie-in of existing facilities, it selected a route almost directly parallel to an existing pipeline right of way. To cause the least nuisance to farming operations and to avoid surface features such as steep hills and canals, the proposed route deviates slightly from the existing pipeline route in three areas: section 35, township 5, range 22, west of the 4th meridian (W4M), sections 7 and

18-6-21 W4M, and section 20-6-21 W4M. CWNG further stated that winter construction would avoid obvious conflicts with farming operations.

CWNG has received easements from all landowners except Mr. John Mehew (owner of Lsds 7, 8, and 9-20-6-21 W4M, and occupant of the northwest quarter of section 21-6-21 W4M), Mr. Edgar Lawrence Hill (owner of the northwest quarter of section 21-6-21 W4M), and Messrs. John and David W. Balderson (owners of the southwest and southeast quarters of section 34-5-22 W4M). CWNG agreed, providing that its winter construction schedule is not compromised, to consult with Mr. Mehew with respect to routing on his land and to approach other surface landowners if any of Mr. Mehew's suggestions result in alternative routes that might affect those other landowners.

4.2 Views of the Interveners

Mr. John Mehew was concerned about the potential disruption of his farming operations and interference with the use and enjoyment of his property. He stated that the proposed pipeline would cross private roads on his property and interfere with irrigation pivots as a result of subsidence over the pipeline. Mr. Mehew did not propose an alternative route for the pipeline across his property, but commented in response to questioning that a route either along fence lines or irrigation canals would be preferable. He also agreed that working with the applicant to identify a route alternative to the one proposed would be acceptable. Mr. Edgar Hill and Mr. K. Balderson (on behalf of Messrs. John and David Balderson) expressed no concerns about the pipeline routing.

4.3 Views of the Board

As discussed in Section 3.3., the Board accepts that looping of the existing pipeline between sections 34-5-22 W4M and 21-6-21 W4M is required. The Board also acknowledges CWNG's efforts to minimize the effects of the pipeline by means of winter construction and by route changes in places where surface farming operations would prohibit use of the existing route or where the potential for reduced erosion and more efficient reclamation was noted. The Board is satisfied the proposed pipeline meets all the requirements of the Pipeline Act and Pipeline Regulations. The Board is also satisfied that issues such as interference with irrigation as a result of subsidence along a pipeline route can be dealt with through the Land Conservation and Reclamation Council.

In view of the fact that no specific alternative routes were recommended, the Board approves the applied-for route. In so doing, the Board accepts CWNG's undertaking to pursue discussions with Mr. Mehew to come to agreement on any route changes that would reduce his concerns. The Board urges CWNG and Mr. Mehew to pursue such discussions and would be prepared to modify the permit approval to accommodate any route changes that may result from this process. Board staff would be available to assist in the process.

5 OTHER POTENTIAL ENVIRONMENTAL CONCERNS

5.1 Views of the Applicant

CWNG stated that operators in the area are responsible, as part of CWNG's on-going maintenance program, to ensure that equipment on site is in good working order. It said pipelines are routinely checked, on an annual basis, for leaks.

CWNG noted that it had only one environmental complaint on record with respect to the Welling Wye compressor station. It confirmed that the complaint led to the discovery of a damaged distribution line, which was subsequently repaired in 1987. CWNG is prepared to work with Mrs. Birch and Mr. Hill to resolve problems that may be associated with the station.

With respect to noise pollution, CWNG stated that the noise level from the Welling Wye facility is the normal noise level expected from a gas-driven compressor. However, CWNG commented that use of the Welling Wye station would be reduced if the approved looping were approved and that, as a result, noise levels would also be reduced.

5.2 Views of the Interveners

Mrs. Alice Birch, who lives about a quarter of a mile east of Welling, and Mr. Edgar Lawrence Hill voiced concerns about odours and noise from the Welling Wye compressor station. Mrs. Birch stated that she had contacted the applicant on numerous occasions to express concern about the effect of such odours on her health. Mr. Hill also raised concerns about the maintenance of the compressor station.

5.3 Views of the Board

The Board is concerned about the environmental matters raised by the interveners. Deficiencies in operating facilities are unacceptable at any time, but particularly when complaints are on record. The Board has requested its field staff to investigate the complaints regarding current problems with the Welling Wye compressor station. With respect to future environmental concerns, the Board notes CWNG's evidence that the proposed pipeline looping will reduce the use of the compressor and should therefore reduce the adverse effects of the compressor station. These facts notwithstanding, the Board would not normally decline applications for new facilities because of problems related to existing facilities. Rather, it would address and resolve the problems directly. Therefore, should the application be acceptable on all other grounds, the Board would not disallow it because of matters raised here.

6 OTHER MATTERS

6.1 Interveners' Views and Applicant's Responses

PCL expressed concern that the proposed pipeline expansion would lead to increased costs for other users of CWNG's system. CWNG responded that while the costs would be included in their rate base, the revenues would also contribute to the revenue requirements, ensuring that no net costs would accrue to other users. In the event that gas reserves are insufficient to keep the loop operating, Gulf stated that it would cover any remaining costs through a lump-sum payment. PCL was not convinced and suggested that it could be sure that no costs would fall on it only if Gulf paid for the pipeline outright.

In response to PCL's concern about potential increase in transportation service rates for the compressor facilities near Lethbridge, Gulf responded that its increased volume along the loop will actually decrease PCL's share of the costs of the compressor installation.

PCL expressed concern about communication between the A Pool and a nearby gas pool underlying the Welling Unit, and that increasing production would shorten the life of the A Pool and aggravate drainage problems in the pool to the east. PCL also expressed concern that the increased rates from the A Pool may cause premature water influx to the gas-producing zone. Gulf responded that both PCL's and Gulf's geological interpretations indicate no communication between the two pools. Gulf further argued that no water is evident in any of the producing wells and that the ERCB could impose future conservation contraints to allay any such concerns when they actually arise.

PCL was concerned about the use of a utility system to transport gas for export and about the overall planning and development in the district. It requested that the pipeline be deferred until local reserves are developed and an infrastructure is complete. Neither the applicant nor the other interveners pursued this issue.

Mr. Bissett (on behalf of Mr. Edgar Lawrence Hill) defined "public interest" as the displacement of personal interests for the good of the group - ie. those not in a conflict of interest - and urged that if the Board is to approve the pipeline, it must ensure that the public interest is protected. The Board should only approve the pipeline subject to the conditions that the leakage from the compressor be constantly monitored to control pollution, that Gulf pay up front for the pipeline, as PCL suggested, and that the Board consider a Q-max order (maximum daily allowable prescribed for the well) so as to extend the life of the reserve.

In response to Mr. Bissett's comments, CWNG argued that the public interest should be related to the legislation and viewed from the perspective mandated in the Oil and Gas Conservation Act that the oil and gas resources of this province will be developed, albeit in an orderly, economic, and efficient manner.

PCL and Mr. Dodic (on behalf of Mr. John Mehew) cited section 11(2) of the Pipeline Act which requires negotiations with landowners for surface access. They requested that, if approval is to be granted, it be subject to the condition under section 11(2) of the Pipeline Act.

Mohawk and CWNG responded that although that section has historically been used, it is not appropriate in this particular case. They suggested that compensation-related issues should be referred to the Surface Rights Board.

6.2 Views of the Board

The Board is satisfied, on the basis of testimony presented, that Gulf would cover the cost of the applied-for pipeline and that there would be no adverse impact from increased costs on PCL or other operators in the area. To the extent that PCL's concerns relate to the tariff structure, they are properly dealt with by the Public Utilities Board. Such matters are not within the jurisdiction of this Board, and are not relevant to this decision.

The Board considers potential drainage effects among competitive operators a matter that should be addressed through mechanisms other than pipeline applications. If lack of a gas contract or lack of access to a processing or pipeline facility demonstrably results in unfair drainage, then the aggrieved party may seek remedy under common purchaser, common processor, common carrier, or rateable take legislation. Such remedies require that the party also have a well or wells ready for production.

While appreciating that increased producing rates in any gas pool may have potentially negative effects, such as possible water influx, the Board considers that all gas producers have an obligation to formulate and to monitor their producing operations so as to minimize any such effects. Also, should the need arise, the Board may impose rate limitations in response to its own monitoring or in response to proposals from any pool operators showing that such limitations are required.

The transportation of gas destined for export from the province on the pipeline system of a public utility is not unusual; may contribute to greater efficiency of gas transportation than would otherwise be possible; and, in the matter at hand, at least does not detract from the applicant's proposal.

The Board does not accept the interpretation of either the applicant or the interveners as to how it should accommodate the "public interest" in its decision. The public interest includes the interests of all parties who may be affected by the Board's decisions including applicants, interveners, the Crown in right of Alberta, and the citizenry at large.

The Board's mandate requires it to consider the interests of all when deciding matters under its jurisdiction.

The Board notes that section 11(2) was incorporated in the Pipeline Act to accommodate special circumstances not prevalent in the matter at hand.

The Board does not believe that any of the "other matters" raised at the hearing are relevant to its decision on the pipeline application.

7 DECISION

The Board is prepared to grant Application 891549 by Canadian Western Natural Gas Company Limited for the reasons discussed in this report, subject to receipt of the approval of the Minister of the Environment respecting environmental matters.

Dated at Calgary, Alberta, on 27 December 1989.

ENERGY RESOURCES CONSERVATION BOARD

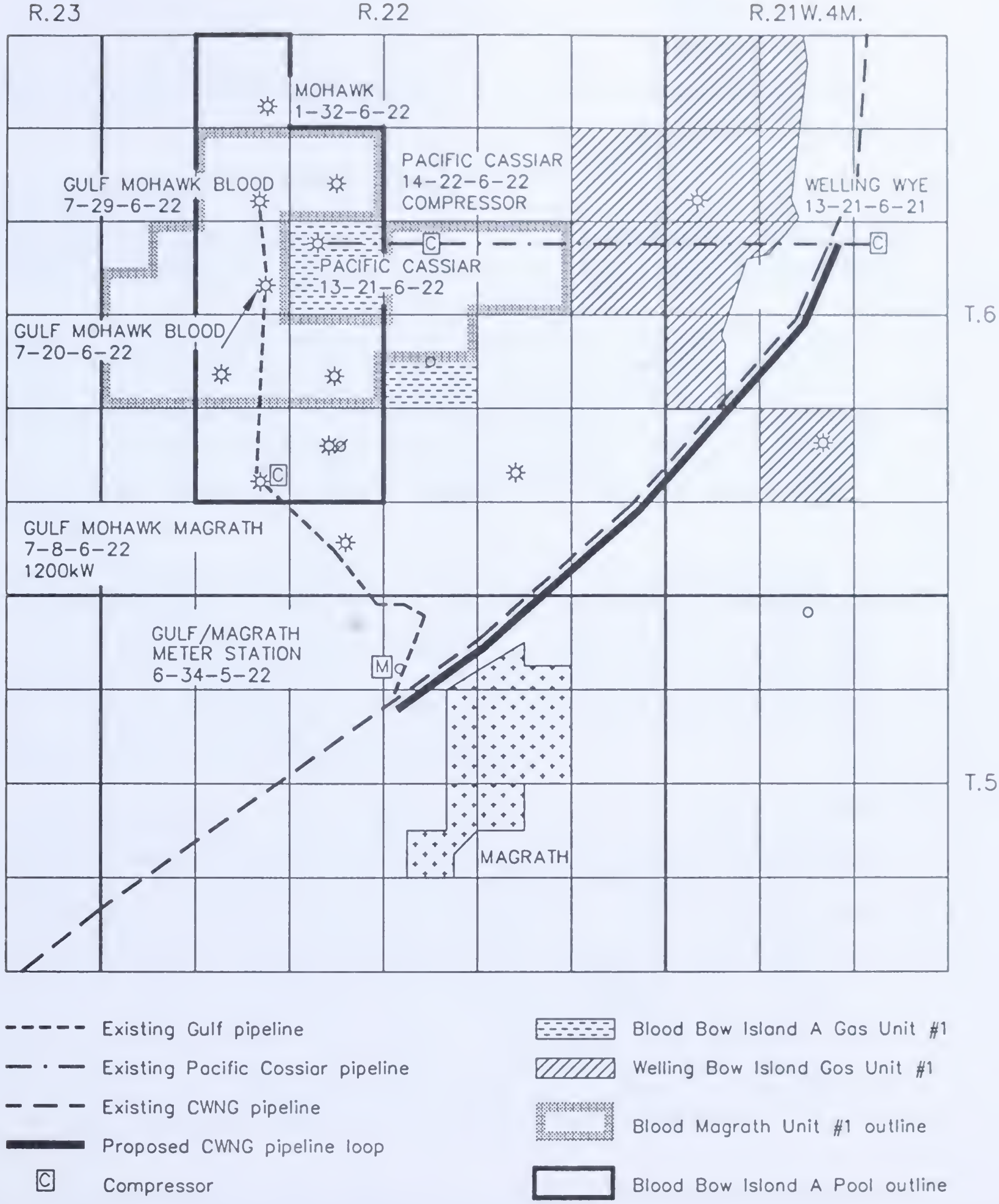
J. P. Prince

J. P. Prince, Ph.D.
Board Member

N. G. Berndtsson, P.Eng.
Acting Board Member

C. A. Langlo

C. A. Langlo, P.Geol.
Acting Board Member



BLOOD MAGRATH AREA PIPELINE NETWORK

Application 891549

Canadian Western Natural Gas Company Limited

D89-11

ERCB

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

THE CITY OF EDMONTON (EDMONTON POWER)
JOINT OWNERSHIP
500-kV TRANSMISSION SYSTEM
KEEPHILLS-ELLERSLIE

Memorandum of Decision
Application 890007

TransAlta Utilities Corporation is the owner and operator of 500-kV electric transmission facilities in the Lake Wabamun-Edmonton area. Edmonton Power applied to the Energy Resources Conservation Board, pursuant to section 17(2)(e) of the Hydro and Electric Energy Act (the Act), for an order requiring TransAlta Utilities to share its interest in the 500-kV transmission system between Keephills and Ellerslie. Edmonton Power requested a 50 per cent share in the ownership of the facilities.

TransAlta Utilities expressed the view that the Act does not grant statutory authority to the Board to order the transfer of ownership of part of the existing transmission system to Edmonton Power. The Board decided to address the jurisdictional matter prior to considering the application. TransAlta Utilities, Edmonton Power, and the Industrial Power Consumers Association of Alberta filed written argument in the matter. TransAlta Utilities and Edmonton Power also filed a "Statement of Agreed Facts" and written reply argument.

The Board has made a careful review of the Act and the arguments filed by interested parties. It concludes that section 17 of the Act is intended to ensure complete co-ordination of the planning, development, and operation of facilities for the generation, transmission, and distribution of electric energy in the province. The Board recognizes that, in order to realize all of the benefits of such co-ordination, certain business arrangements may have to be made among the owners of facilities. It also recognizes that a direction issued by it under section 17 of the Act may have the effect of compelling the owners of facilities into business arrangements. Notwithstanding this possible result of such a direction, the Board is not satisfied that section 17(2)(e) of the Act authorizes it to order the transfer of ownership of all or part of a power plant, transmission line, or electric distribution system.

The Board is therefore not prepared to proceed with a consideration of the subject Edmonton Power application.

DATED at Calgary, Alberta, on 1 May 1989.

ENERGY RESOURCES CONSERVATION BOARD

G J DeSorcy

G. J. DeSorcy, P.Eng.
Chairman

DECISIONS

ISSUED IN 1990

NUMBER	APPLICATION NUMBER	TITLE	DATE OF ISSUE
D 90-1	890963	BOARD PROCEEDING TO REVIEW ELECTRIC GENERATION PLANNING PARAMETERS	30 March 1990
D 90-2	890978, 890979 891184, 891646 891647	VICTOR R. DURISH AND SEASCAPE OIL & GAS LTD. ASSIGNMENT OF PIPELINE LICENCE, COMPULSORY POOLING, AND TRANSFER OF WELL LICENCE, MALMO FIELD	29 March 1990
D 90-3	891846	CHESAPEAKE RESOURCES LTD. APPLICATION FOR A WELL LICENCE WHITEMUD AREA	4 June 1990
D 90-4	891671	POWER RESOURCE DEVELOPMENT CORP. 18-MW WOOD-WASTE-FIRED ELECTRIC POWER PLANT WHITECOURT AREA	17 May 1990
D 90-5	891967	City of Medicine Hat POWER PLANT EXPANSION	7 August 1990
D 90-6	891425	ALTEX RESOURCES LTD. BITTERN LAKE GAS PROCESSING PLANT	18 May 1990
D 90-7	891642	DAISHOWA CANADA CO. LTD. PEACE RIVER PULP MILL INDUSTRIAL DEVELOPMENT PERMIT TO USE GAS AS A SUPPLEMENTARY FUEL	18 July 1990
D 90-8	890971	CAROLINE BEAVERHILL LAKE GAS DEVELOPMENT APPLICATIONS SHELL CANADA LIMITED HUSKY OIL OPERATIONS LTD	31 August 1990
D 90-9	900374	GULF CANADA RESOURCES LIMITED COMPULSORY POOLING FENN-BIG VALLEY FIELD	24 August 1990
D 90-9	900374	GULF CANADA RESOURCES LIMITED COMPULSORY POOLING FENN-BIG VALLEY FIELD	14 December 1990
D 90-9	900374	GULF CANADA RESOURCES LIMITED COMPULSORY POOLING FENN-BIG VALLEY FIELD	27 March 1991

D 90-10	891878, 900713	APPLICATIONS FOR REDUCED DRILLING SPACING UNITS, MOBIL OIL CANADA AND PASSBURG PETROLEUMS LTD. DRUMHELLER D-2 B LOOL	20 September 1990
D 90-11	891965	DEPARTMENT OF ENERGY, GOVERNMENT OF ALBERTA. RESCISSION OFSPECIAL GAS DRILLING SPACING UNITS PEMBINA AND WESTEROSE AREAS	30 October 1990
D 90-12	900948	BLUE RANGE RESOURCES LTD. APPLICATION TO AMEND WELL LICENCE NO. 0124875. SYLVAN LAKE FIELD	1 October 1990
D 90-13	900909, 900910 900911, 900912 900913, 900965 900723	CORVAIR OILS LTD. APPLICATIONS FOR WELL LICENCES, BATTERY MODIFICATION AND REDUCED OIL WELL SPACING. ARMISIE FIELD	20 November 1990
	901203	MR. D. BRUCE COOK, CANCELLATION OF WELL LICENCES NO. 63496, 84329 and 85265	20 November 1990
D 90-14	891717	HOME OIL COMPANY LIMITED REDUCED DRILLING SPACING UNITS WOOD RIVER FIELD	1 October 1990
D 90-15	890715	BOW VALLEY INDUSTRIES LTD. LONG-TERM GAS REMOVAL	22 October 1990
D 90-16	901312	RANCHMEN'S RESOURCES LTD. REVIEW OF WELL LICENCE KNOPCIK FIELD	23 October 1990
D 90-17	891183	HUSKY OIL OPERATIONS LTD. SUBSURFACE DISPOSAL OF PRODUCED WATER. FISHER AREA	1 February 1991
D 90-17	891183	HUSKY OIL OPERATIONS LTD. SUBSURFACE DISPOSAL OF PRODUCED WATER. FISHER AREA	2 May 1991
D 90-18	901544	THE CITY OF MEDICINE HAT POWER PLANT EXPANSION	15 November 1990

ALBERTA. ENERGY RESOURCES CONSERVATION BOARD

DECISIONS

1990

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

BOARD PROCEEDING TO REVIEW ELECTRIC GENERATION PLANNING PARAMETERS

Decision Report D 90-1
Proceeding 890963

1 INTRODUCTION

1.1 The Proceeding and the Meeting

In June 1989, TransAlta Utilities Corporation, Alberta Power Limited, and The City of Edmonton (the Utilities) requested the Energy Resources Conservation Board (ERCB) to review certain matters relating to generation capacity expansion planning for the Alberta Interconnected System (AIS). These matters were presented in three reports which dealt with the assessment of peak continuous ratings of the AIS generating units, the amount of reliance that should be placed on external interconnections, and the adoption of an interim reliability criterion pending the outcome of a full-scale review of the existing criterion.

The request was considered pursuant to section 4 of the Hydro and Electric Energy Act.

To consider the matters raised in the above-mentioned reports, the Board held a public meeting in Calgary on 14-16 November 1989, with F. J. Mink, P.Eng., J. P. Prince, Ph.D., and E. J. Morin, P.Eng., sitting. Those who participated in the discussions at the meeting are shown in the following table.

1.2 Participants at the Meeting

Principals and Representatives (Abbreviations Used in Report)	Witnesses
TransAlta Utilities Corporation T. Dalgleish	G. Steeves, P.Eng.
Alberta Power Limited R. Romanow	B. Laing, P.Eng.
The City of Edmonton G. Salembier (the Utilities)	D. Lewin, Ph.D., P.Eng.
The Industrial Power Consumers Association of Alberta/The Canadian Petroleum Association (IPCAA/CPA) A. L. McLarty	R. Billinton, D.Sc., P.Eng. C. Buchanan, P.Eng. M. Drazen H. Garritsen D. Self M. Smith
The City of Calgary R. F. Goss	
The City of Lethbridge O. Erdos, P.Eng.	
The City of Medicine Hat W. Kerr, P.Eng.	
Energy Resources Conservation Board staff M. L. Asgar-Deen, P.Eng. P. E. Wickel T. Y. Chan, Ph.D., P.Eng. R. L. Schroeder	

A glossary of terms and their abbreviations used in this report is included in Appendix A.

2 ISSUES

The Board believes the following to be the major issues that were raised at the meeting:

- Capacity above Maximum Continuous Rating (MCR) - How should incremental capacity above MCR be recognized?

- o AIS reliance on external ties - How much should the AIS rely on external interconnections for generation planning purposes?
- o Reliability Criterion - Is there a need for an interim generation planning reliability criterion?

3 CAPACITY ABOVE MAXIMUM CONTINUOUS RATING

3.1 Views of the Utilities

The Utilities define MCR of a thermal unit as the maximum output for which the unit has been designed to operate on a long-term, continuous basis. Among utilities in North America, MCR is commonly used for capacity reliability calculation. Nevertheless, the generating utilities in Alberta, recognizing that thermal units can deliver capacity above MCR, have for several years used a capacity level higher than MCR for capacity planning purposes. The higher capacity level has historically been defined as the Peak Continuous Rating (PCR).

Prior to 1988, the Tested Maximum Rating (TMR) of a unit was used as its PCR (see Appendix A). As well, the total AIS capability was based on TMRs of all the generating units. In 1988, the AIS capability based on the sum of unit TMRs was 450 MW higher than that total based on unit MCRs. Historically, generating units have been assumed to have the same reliability when operating at TMR as that at MCR. Accordingly, the Utilities presumed that if all the units were operating at MCR, they could still rely on 450 MW of PCR capacity to meet load demands when required. However, the operators of the system found that, on many occasions, when the system needed to rely on capacity above MCR to meet the load demand, the additional available capacity was much less than 450 MW. It was concluded that the portion of the capacity above MCR was less reliable than the capacity up to MCR.

In 1987 the Utilities initiated a procedure to determine the amount of capacity above MCR that could be reliably included in the estimation of available capacity. During the winter period of the 1987/88 climatic year and again in 1988/89, the Utilities designed a test by randomly selecting generating units and, with 30 minutes notice, requiring them to generate at TMR for 2 hours. The results of these "drill tests" were adopted as measures of each unit's availability to generate in excess of MCR and, if available, their capability to achieve TMR. The results, calculated for all units tested, were:

	Availability (1)	Capability (2)	(1) x (2)
1987/88	45%	85%	38%
1988/89	59%	60%	35%

Based on the results of the drill tests, the aggregate of the PCRs for the units on the AIS is 225 MW greater than the sum of the MCRs. The reduction of capacity above the MCRs reflects the lower reliability of that capacity within the AIS.

In response to some participants' proposals for using TMRs and Derated Adjusted Forced Outage Rates (DAFOR) in the reliability model, the Utilities stated that the result could not be valid because the Load Carrying Capability (LCC) so calculated was lower than that calculated by using MCR in conjunction with FOR. The latter calculation is believed to yield the lowest LCC among calculations which use all possible combinations of different types of unit ratings and outage rates.

The Utilities asked the Board to permanently adopt the proposed methodology for determining PCRs. They also requested the Board to allow them to make changes to PCRs and other characteristics without requiring formal approval by the Board in the future.

3.2 Views of the Participants

IPCAA/CPA and The City of Calgary did not agree with continuing to use TMRs nor the immediate adoption of the proposed new PCRs. IPCAA/CPA suggested that if TMRs had to be used, they should be used in conjunction with the DAFORs in the two-state model.

Notwithstanding the above suggestion, IPCAA/CPA submitted that the issue of changing the PCRs as proposed could not be viewed and evaluated in isolation. This should be done in the context of the reliability model and the related calculations. It suggested that multi-state models would be more appropriate to represent generating units that have different probabilities of outage for different modes of operation.

Thus IPCAA/CPA believed that the logical course would be to revise the existing model or to devise a new model that allows for multi-state representation of a generating unit.

3.3 Views of the Board

The Board accepts that the Utilities' drill tests suggest that the sum of the TMRs of individual units may overestimate the overall capability of the generating system to respond to demand for electric energy. Additionally, the Board considers that the sum of unit MCRs would tend to underestimate the overall capability of the generating system. Therefore, the Board is of the view that, for planning purposes, the generating capacity of each coal-fired unit should be based on a value that is higher than its MCR but lower than its TMR. Although this conceptually corresponds to the PCR as now proposed by the Utilities, it does not mean that the Board accepts the values that have been proposed by the Utilities.

The Board considers that there is some merit in the drill tests performed by the Utilities for determining unit PCR. The drill test procedure appears to be a reasonable way to produce data for assessing the ability of each thermal unit to respond to demands for its maximum output. However, the Board has reservations regarding the use of system availability and capability factors to calculate the PCRs of individual generating units which are of different ratings and different years of service, use different quality of fuel, and are operated and maintained by different personnel.

In addition, the Board has serious reservations regarding the derivation of the system availability and capability factors and, in particular:

- During the first year of testing, units were removed from the draw after completing two successful tests. This may bias the results, as some units became unavailable for the draw.

- The calculation of availability factor was not weighted by the size of each thermal unit in the first year. This may bias the results if the majority of the units had either a higher-than-average or lower-than-average capacity.

- Although the products of availability and capability are approximately equal for the 2 years of test, the Board notes that there was significant difference in availability factors from one year to the next. A similar large difference was experienced for the capability factors, but in the opposite direction. The Board believes these differences may be indicative of deficiencies in the procedure.

Therefore, the Board cannot totally accept the procedure proposed by the Utilities at this time. Similarly, the Board cannot confirm, as requested by the Utilities, that changes to PCRs and other unit characteristics be recognized without formal review by the Board as has been the case in the past. It believes that until the problem is better understood and the solutions determined with more confidence, it must be kept fully informed. It believes that the current study by the Utilities of reliability criteria affords an opportunity to refine the testing procedure and perhaps apply the methodology in a rigorous fashion. Hence, the Board expects to be kept informed by the Utilities as more tests are conducted and procedures are improved.

In considering the testing that has been done, the Board is of the view that, during the interim, for each coal-fired unit an estimated PCR equal to its MCR plus 50 per cent of the incremental capacity between its MCR and TMR is a reasonable and acceptable approximation and should

be used for planning purposes. For example, based on evidence at the meeting the PCR for Battle River 5 would be 391 MW[1].

4 AIS RELIANCE ON EXTERNAL TIES

4.1 Views of the Utilities

The Utilities stated that, prior to 1986, the AIS had no major interconnections with utilities outside the province. Consequently, the total demand on the system had to be supplied from generating capacity within Alberta. To meet a system reliability criterion of 0.2 days per year (d/yr), the Utilities had to maintain a capacity reserve of 22 to 25 per cent of the peak load.

In 1986, the 500-kV Alberta to B.C. interconnection was commissioned. Since then, the AIS and B.C. Hydro have been able to use the tie line for sharing reserve capacity. Although there is no firm power purchase agreement between the Utilities and B.C. Hydro, for planning purposes a capacity value of 300 MW was assigned to the tie line in 1986. By relying on the B.C. tie for 300 MW, the Utilities were able to decrease the AIS internal capacity reserve to 17 per cent and still meet the reliability criterion of 0.2 d/yr.

In 1989, the Saskatchewan tie was commissioned. However, it is unable to be used for reserve capacity-sharing purposes until 1995. After 1995 the AIS will rely upon a capacity reserve of 125 MW from Saskatchewan.

The Utilities, in considering AIS reliance on external ties, analysed such factors as the capability of neighbouring systems to provide support and to reciprocate, the physical capability of the interconnection facilities, and the consequence of a forced outage on the interconnection, as well as a number of judgmental factors including financial risk and the experience of other utilities.

The Utilities submitted that reciprocity is the most constraining technical factor in determining how much reliance should be placed on the B.C. interconnection (400+ MW in 1986 and increasing as the AIS system grows). However, they suggested that judgmental factors should also be accorded considerable importance in determining the appropriate level of reliance on interconnections. These judgmental factors led the Utilities to recommend that the AIS depend on the external tie with B.C. for no more than 25 per cent of its reserve requirements (300 MW in 1986 and increasing as the system grows).

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1 $$PCR = MCR + \frac{TMR-MCR}{2} = 372 + \frac{410-372}{2} = 391 \text{ MW}$$

The Utilities indicated that, throughout North America, the level of generation reserves is determined by many different approaches, with no set standards regarding the adequacy of individual systems. However, the basic intent is that each utility system will have sufficient generating facilities or firm purchase agreements to meet its own requirements so as not to place unreasonable dependence on an interconnection. The Utilities believed that, since the B.C. tie is a weak interconnection in comparison to others in North America, and because the AIS has a higher load factor, the AIS requires higher reserve levels.

Furthermore, the Utilities indicated that the reliability criterion review report, which recommends the adoption of an interim internal reserve capacity of 17 per cent of peak load, is consistent and reasonable when compared with other systems. The Utilities recognized that interconnections provide an option to reduce internal capacity but beyond some point this is reasonable only if there are firm purchase power agreements in place. The Utilities submitted that, in the absence of firm contract agreements, no more than 25 per cent of the AIS capacity reserve requirements should be provided through interconnections.

The Utilities submitted that, if they were to rely on an interconnection capacity of more than 300 MW, the AIS would become susceptible to high financial risk because B.C. Hydro could charge whatever the market would bear. They indicated that this could result in charges of 10 cents or more per kilowatt-hour (kW.h). Therefore, the Utilities stated that further increase of reliance on the interconnection should not be considered without contractual arrangements with B.C.

4.2 Views of the Participants

IPCAA/CPA submitted that the results of the Utilities' studies on reliance on external ties were obtained by conservative analysis and that peak load diversity between Alberta and B.C. was not taken into consideration. It suggested that, if a less conservative analysis were done, and the peak load diversity were considered, Alberta could rely on B.C. for 200 MW over and above the 400+ MW estimated by the Utilities as the most constraining technical factor.

IPCAA/CPA contended that relying on external ties for an additional 100 MW over the 300 MW proposed by the Utilities would reduce internal reserves to 15 per cent. This would be within the range of 15-20 per cent which the Utilities indicated is common throughout North America. As well, an increased reliance of 100 MW would still leave sufficient reserve capacity on the tie line for planning flexibility.

IPCAA/CPA submitted that an economic analysis is required to determine the optimum reliance on external interconnections. It indicated that relying on external ties for an additional 100 MW would cost $2-3 million a year, assuming an energy cost of 10 cents per kW.h. However, the cost of 100 MW of generating capacity is estimated to be $20 million per year based on a cost of $1200 per kilowatt.

The City of Calgary submitted that maintaining a reasonable amount of internal reserve is important. It submitted that reliance on external interconnections to provide 25 per cent of total reserve is judgmental and is not based on hard evidence. The City stated that, until all issues before the Board are resolved, it would be appropriate to rely on external interconnections for more than 25 per cent of required reserves.

4.3 Views of the Board

The Board acknowledges that non-technical factors may be important in determining the level of reliance placed on external ties. However, it is not satisfied with the evidence presented to support the Utilities' judgment that only 25 per cent of Alberta's generation requirement should be provided through external interconnections. It is of the view that reliance on external interconnections should be based predominantly on technical factors unless that imposes an unacceptable risk to the consumer. The Board accepts that reciprocity is the most restrictive technical factor, and should be used to determine the level of reliance placed on external ties.

The evidence presented by the Utilities, as shown on Figure 7 of the Utilities' report entitled "AIS Reliance on External Interconnections", suggests that, at this time, the reliance on interconnections based on technical factors is approximately 100 to 150 MW above that based on non-technical factors. The Utilities submitted that, if the AIS were to increase the reliance on the B.C. tie by 100 MW, the cost of the increased energy dependence from B.C. would be comparable to the cost of installing and operating a 100-MW gas-fired turbine unit in Alberta. As well, evidence presented further suggests that the level of maximum reliance based on non-technical factors was derived using a conservative method. Having reviewed this information, the Board is satisfied not only that Alberta consumers would not be exposed to unacceptable financial risks, but also that planning flexibility would be maintained if the maximum reliance based on technical factors were placed on the B.C. tie.

In general, the Board believes that co-ordinated planning of future capacity among neighbouring power systems may allow significant mutual benefits in terms of increased reliability and possible deferral of additions to capacity. In turn, it expects that the Utilities would find B.C. Hydro to be receptive and reasonable in negotiating an increased reliance on the Alberta-B.C. tie. A full review of this

matter would be of considerable interest before a permanent criterion is adopted. The Board would request the Utilities to explore, with B.C. Hydro, all reasonable options to use of the tie to meet system reliability and identify the most cost-effective option for planning purposes. These findings could be reviewed in conjunction with the other findings on the reliability criteria. In the meantime, the Board believes capacity additions to the AIS should be planned by relying on the B.C. tie to the level defined by technical factors only.

5 RELIABILITY CRITERION

5.1 Views of the Utilities

The Utilities noted that the existing reliability criterion, which was adopted in 1973, required recalibration or replacement due primarily to changes in electricity consumers' demand patterns. They argued that development of a replacement system cannot be completed sufficiently early to accommodate planning decisions for new plants. Therefore, an interim criterion should be adopted.

The Utilities stated that the changing characteristics of the AIS, together with changes in consumer demand patterns and attendant load duration curves, had eroded the validity of the existing planning criterion of 0.2 peak d/yr Loss of Load Expectation (LOLE). The Utilities had encountered real operating conditions where reserve margins were significantly different from those identified by the planning models.

The Utilities stated that in 1973 a decision was made to calculate the annual LOLE using daily peak loads instead of hourly peak loads. This load representation was valid because the daily peak load at that time was much greater than the loads at other hours of the day. Since then, the daily load shapes have changed significantly such that there are many more hourly loads that are close to the daily peak load. Therefore, the hourly loads, in addition to the daily peak load, should also be recognized in the calculation of the LOLE. If they are not, the risk of not meeting the loads would increase.

The Utilities performed reliability evaluations using hourly loads instead of a daily peak load representation. The results indicated that the current generation planning reliability criterion overstated the load carrying capability (LCC) of the AIS by 252 MW (or, on average, approximately 310 MW of plant capacity).

Given these and other shortcomings, the Electric Utility Planning Council (EUPC) has committed to review and recommend an appropriate planning reliability criterion. It will encompass a thorough analysis of the established techniques used by others in the industry, but tailored to Alberta requirements. The Utilities submitted that these studies and recommendations would not be available for implementation before 1991. They stated that an interim criterion is needed in order to

1. assist the Public Utilities Board (PUB);

2. assist in the determination of the commissioning date of the second unit at the Genesee power plant; and

3. allow the generation planning process to continue without delays, in case new generating capacity is needed shortly after 1991.

In response to concerns raised respecting the assumptions made in their calculations of LCC overstatement by the current 0.2 d/yr LOLE criterion, the Utilities argued that use of Forced Plus Maintenance Outage Rate (FMOR) was appropriate in models which consider hourly peak loads because the outage rate of generating units must include both forced and maintenance outages. They stated that in models that consider daily peak loads, maintenance outages can be ignored because maintenance is assumed to be performed the following weekend.

In response to the argument by IPCAA/CPA that, despite shortcomings, the existing criterion had not resulted in shortages of power and that surplus capacity had occurred in the past years, the Utilities noted that the surplus capacity was due to forecasted loads not materializing and that the surplus had obscured the impact of the shortcomings of the existing criterion.

The Utilities proposed that an interim generation planning criterion of 17 per cent internal reserve capacity be adopted until a full review and recommendation on an appropriate generation planning reliability criterion is completed and presented to the Board. They arrived at the proposed criterion by reducing the LCC by 252 MW from that which was obtained by using the current 0.2 d/yr LOLE criterion.

5.2 Views of the Participants

IPCAA/CPA did not agree with the Utilities respecting the need for an interim planning reliability criterion in order to make decisions and to allow planning to continue. However, it agreed that the existing criterion needed reviewing and noted that the review was already under way and would come to fruition in a year or so.

IPCAA/CPA stated that the real issue is whether there is an urgent need to adopt an interim criterion in place of the existing one. It submitted that there is no urgency for an interim criterion. Furthermore, IPCAA/CPA suggested that adopting an interim criterion might have a significant adverse impact on electrical consumers. For instance, Genesee 1 might be commissioned earlier than really needed and there is also the possibility of approving another new generating unit earlier than required.

IPCAA/CPA stated that the current criterion has served well in the last 16 years and that there had not only been enough capacity each year but substantially more than enough. It was of the view that, in the interim period of approximately 1 year, the AIS could still rely on the current criterion and, if necessary, use the planning flexibility provided by the B.C. and the Saskatchewan ties.

The City of Calgary was of the view that an interim criterion was not needed and it proposed that the current 0.2 d/yr LOLE criterion be used until the detailed study on an appropriate generation planning reliability criterion is concluded and implemented. The City of Calgary also stated that, if an interim criterion were adopted, it should be used only for planning purposes and should be applicable only to the commissioning date of Genesee 1.

In critiquing the Utilities' analysis of the reliability criteria, IPCAA/CPA questioned the methodology used to arrive at their claimed amount of LCC overstatement. It submitted that, in obtaining the 252 MW of LCC overstatement, the Utilities not only changed the shape of the load from 1972 to 1988, but also changed the FOR of generating units to FMOR in the calculation of reliability on an hourly basis. It argued that by using FMOR, which is higher than FOR, the reliability of all the thermal units was reduced as compared to the 0.2 d/yr in the base case. Therefore, it exaggerated the LCC overstatement. IPCAA/CPA stated that consistency should have been maintained throughout the entire analysis.

IPCAA/CPA also argued against the use of FMOR in reliability calculations in general, as done by the Utilities in their analysis of LCC overstatement. It stated that using FMOR is appropriate for production costing models but not for reliabilty calculations because, by definition, a maintenance outage is one that can be deferred past the next weekend. Therefore, it did not represent a random situation. FOR, however, represented the randomness of generating outages and should have been used for reliability throughout the entire analysis.

IPCAA/CPA noted that, since the Utilities were using an hourly calculation of LOLE in their analysis, they should have modelled the capacity assistance from B.C. on an hourly basis as well as taking into account peak load diversity between the AIS and the B.C. electric system. IPCAA/CPA stated that, if this had been done, it would have diminished quite considerably the urgency of the Utilities to discard the current 0.2 d/yr LOLE criterion.

IPCAA/CPA stated that it is not appropriate to replace a responsive probabilistic criterion, such as the one currently in place, by an inflexible deterministic per cent reserve, as proposed by the Utilities. IPCAA/CPA argued that a per cent reserve criterion will not permit the proper modelling of independent power sources and co-generation.

5.3 Views of the Board

The Board believes that the appropriate basis on which to judge the necessity of an interim criterion is whether or not the existing one could result in inordinate risk that facilities might not be available to meet the demands of consumers. The Board also believes that the evidence which may prompt an adjustment to the existing criterion should be sufficiently compelling that it would in all likelihood be recognized in new criteria in the future.

In appraising the need for an interim criterion the Board noted that several facilities decisions, most notably the commissioning of Genesee 1, are likely to be placed before the Board before a review of the existing criterion is complete. Accordingly, the Board is satisfied that if the shortcomings of the existing criterion result in significant reduction in reliability it should adopt an interim criterion. To do otherwise could expose consumers to forced outages or selection of supply options that are less cost-effective.

The Board accepts that the shortcomings of the existing criterion are primarily due to consumer demand patterns and attendant load duration curves that have changed significantly over the past decade. It believes that these changes of demand patterns are likely to persist and will have to be addressed in the upcoming review.

The Board is convinced by the evidence that it would not be appropriate to continue to use the current 0.2 d/yr LOLE criterion exclusively because it does not adequately consider changed demand patterns that contribute to the annual LOLE. However, it is of the view that the current criterion can be used in the interim, providing that the annual LCC is adjusted by an appropriate amount such that it would reflect the increase in the loads relative to the daily peak.

The Board agrees with IPCAA/CPA that the probabilistic criterion has served the industry well and would appear to have intrinsic advantages over a deterministic approach. Accordingly, the Board cannot agree that it should be dropped, particularly if measures can be found to accommodate the factors which presently reduce its reliability.

The Board agrees with IPCAA/CPA, that in order to determine the LCC overstatement due to changes in load patterns, the Utilities should have maintained consistency in their analysis, ie, they should have changed only the load patterns, leaving everything else unchanged. Such analysis, which was later supplied by the Utilities as part of an undertaking, shows that the LCC overstatement of the current criterion, due to change in load shape only, is 193 MW of LCC or 235 MW of average plant capacity. The Board would consider it reasonable to adjust the LCC by 200 MW as an interim recognition of the change in demand patterns.

Accordingly, the Board believes that, as an interim measure, for generation planning purposes, the Utilities should continue to use the current criterion of 0.2 d/yr as their theoretical reliability criterion but should apply a 200-MW discount to the computed annual LCC in order to determine if additional capacity needs to be added to the AIS. The Board favours this approach instead of a straight per cent reserve criterion because it believes that until it can be shown to the contrary, there are merits in using probabilistic methods for determining capacity additions to the AIS.

6 SUGGESTIONS FOR THE FULL REVIEW OF GENERATION PLANNING PARAMETERS

The Board recommends that the full review of the planning parameters should incorporate the following:

- The review and recommendations to determine PCR should be based on statistically reliable procedures and should conform with the fundamental principles of the generation reliability modelling used.

- Consideration should be given to representing the generating units by multi-state unit models.

- The Utilities should consider modelling capacity assistance as multi-state equivalent generating units.

- A review should be made regarding the possibility of deferring additional capacity by co-ordinating the planning of future capacity among neighbouring power systems.

- The Utilities should incorporate a comparison of the pros and cons of probabilistic criteria versus deterministic ones.

- A full discussion should be made of all related costs and benefits when establishing the appropriate level of reliability desired for the AIS.

7 FINDINGS AND CONCLUSIONS

A review of the evidence confirms that changes in the Alberta electric system, the operating practices of the Utilities, and consumer demand over the past decade support the need for a thorough review of the generation planning parameters presently used. Given that the formal review cannot be completed before 1991, the Board is satisfied that some adjustment to those factors affecting the existing parameters should be adopted as an interim measure. These adjustments are largely to reflect the ongoing expectation of consumers for reliable power and the capability of the system to deliver it.

The Board believes that testing procedures to determine the ratings of individual thermal units should be investigated as recommended in section 6 before they can be permanently adopted for reliability purposes. In the interim, the Board recommends that for planning purposes the rating for each coal-fired unit be set at MCR plus 50 per cent of the incremental capacity between MCR and TMR.

The Board also found that, in the short term, greater reliance can be placed on the B.C. interconnection than is presently proposed by the Utilities. The Board believes that the Utilities should explore all options that can be put in place to avoid undue cost implications for the consumer in the long run and report its findings in due course.

Finally, the Board believes that some interim adjustment should be made to the reliability criterion to recognize the change in electric demand patterns which has occurred since it was established in 1973. The LCC determined by using the 0.2 d/yr LOLE criterion should be adjusted downward by 200 MW until a new criterion is adopted.

DATED at Calgary, Alberta, on 30 March 1990.

ENERGY RESOURCES CONSERVATION BOARD

F. J. Mink, P.Eng.
Board Member

J. P. Prince, Ph.D.*
Board Member

E. J. Morin, P.Eng.
Board Member

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* J. P. Prince, Ph.D., was unavailable for signature but concurs with the contents and with the issuing of this decision.

APPENDIX A

GLOSSARY

Availability Factor

Availability factor is the percentage of the time that a coal-fired generating unit is available for TMR, when it is already in service.

Capability Factor

Capability factor is the percentage of the difference of TMR and MCR that a coal-fired unit is capable to produce, when it is available for TMR.

Daily Peak Load Representation

Representation of the loads in a power system by the daily peaks only. A full-year load is therefore represented by 365 daily peak loads.

Derated Adjusted Forced Outage Rate (DAFOR)

A measure of the rate at which a generating unit is out of service because of extended maintenance and planned outage time, scheduled and forced derating period, and available but not operating conditions. These are all taken into consideration to arrive at the Equivalent Forced Outage Time and Equivalent Operating Time. DAFOR is the ratio of Equivalent Forced Outage Time to Equivalent Forced Outage Time plus Total Equivalent Operating Time.

Drill Test

During the winter months of 1988 and 1989, the Utilities ran PCR drill tests on all coal-fired generating units. The tests involved selecting units at random without prior knowledge of the power plant staff and requesting the unit to deliver TMR within 30 minutes.

Equivalent Unit Representation (Multi-state)

Representation of the capacity assistance available from external interconnections as a single generating unit of varying capacity. Higher capacities are associated with smaller probabilities of availability.

Forced Outage Rate (FOR)

A measure of the rate at which a generating unit is forced out of service when it is expected to be available. It is the ratio of Forced Outage Time of a generating unit to the Operating Time plus Forced Outage Time.

Forced Plus Maintenance Outage Rate (FMOR)

A measure of the rate at which a generating unit is unavailable because of forced outages and maintenance outages. It is a ratio of Forced Outage Time plus Maintenance Outage Time to the Operating Time plus Forced Outage Time plus Maintenance Outage Time.

Hourly Peak Load Representation

Representation of the loads in a power system by hourly peaks. A full-year load is therefore represented by 8760 hourly peak loads.

Internal Reserve Capacity

The per cent by which installed generating capacity, excluding capacity available through interconnections, exceeds the annual peak load.

Load Carrying Capability (LCC)

Maximum annual peak load that a system can accommodate without exceeding its reliability criterion.

Loss of Load Expectation (LOLE)

The expected number of hours (or days) in which the generating capacity may not be able to supply the load.

Maximum Continuous Rating (MCR)

The Maximum Continuous Rating of an electric generating unit is the net load which the unit is capable of carrying at normal operating conditions when operated continuously for extended periods of up to 8000 hours per year or on a monthly basis, 700 hours per month and ignoring derating.

Multi-state Model

Representation of generating units as multiple blocks of capacity, ie, not only in the full output and out-of-service states, but also in intermediate or partial output states.

Peak Continuous Rating (PCR)

The Peak Continuous Rating of an electric generating unit is the highest output in MW.h/hr which can be attained with reasonable certainty. For gas-fired and hydro-electric units this value is the same as the TMR. For a coal-fired steam unit the TMR cannot be achieved as regularly as can the MCR. In order to account for this lower reliability the PCR of a coal-fired steam unit is calculated by adjusting TMR.

Peak Load Diversity

Difference in the time of occurrence of peak loads between neighbouring power systems.

Production Cost Model

A computer program that calculates the energy and production costs of generating units within a power system.

Reliability Criterion

Criterion used to signal when new generating capacity is needed in a power system. In Alberta, the reliability criterion has been that the loss of load expectation on the AIS should not be more than 0.2 d/yr.

Reliability Model

A computer program that represents the reliability of a power system in mathematical form.

Tested Maximum Rating (TMR)

Tested Maximum Rating of a thermal electric generating unit is the highest average output in net MW.h/hr based on the two sets of highest five consecutive hours of output in net MW.h obtained from the unit records for the period from 1 December to the end of February in one of the last three climatic years. The output in any one hour can only be utilized in one set of five consecutive hours. The two sets of highest five consecutive hours of output must be from one climatic year only.

If there were no suitable records available in the last three climatic years then judgment is used in establishing these values based on other experience with similar units and manufacturer's design data.

Two-state Model

Representation of generating units as a block of capacity that can be in only two states: either operating at full output or out of service.

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

VICTOR R. DURISH AND
SEASCAPE OIL & GAS LTD.
ASSIGNMENT OF PIPELINE LICENCE,
COMPULSORY POOLING, AND
TRANSFER OF WELL LICENCE
MALMO FIELD

Decision D 90-2
Applications 890978, 890979,
891184, 891646, and 891647

1 INTRODUCTION

1.1 Applications

Victor R. Durish (Mr. Durish) and Seascape Oil & Gas Ltd. (Seascape) applied in five applications for an assignment of pipeline licence, a compulsory pooling order, and a transfer of well licence.

Applications 890978 and 890979 are competing applications filed by Mr. Durish and Seascape respectively, pursuant to section 24(6) of the Pipeline Act, requesting a transfer of Pipeline Licence No. 19216 to each of them from WRM Resources Ltd. (WRM).

The pipeline will be used for transporting sour natural gas from the well, LOBELL ET AL MALMO 13-21-43-22 (13-21 well), to the Gulf Canada Resources Ltd. (Gulf) gas battery located in legal subdivision 10 of section 29, township 43, range 22, west of the 4th meridian.

Applications 891184 and 891647 are competing applications filed by Mr. Durish and Seascape respectively for an order designating that all tracts within the drilling spacing unit comprising section 21 of township 43, range 22, west of the 4th meridian (section 21), be operated as a unit for the production of gas from the Malmo D-3 B Pool through the 13-21 well.

Mr. Durish's Application 891184 was made pursuant to sections 7, 72, 73, and 78 of the Oil and Gas Conservation Act (the Act); Seascape's Application 891647 is pursuant to section 72 of the Act.

Application 891646 was filed by Mr. Durish, pursuant to section 13 of the Act, to transfer Well Licence No. 75430 for the 13-21 well to Mr. Durish from Seascape.

During the course of the hearing, the Board panel hearing the application advised that it would be reviewing the October 1987 transfer of Well Licence No. 75430 from WRM to Seascape in accordance with the authority given it under section 42 of the Energy Resources Conservation Act.

While no formal interventions were filed with respect to the applications, both applicants advised the Board panel that the information presented during the course of the hearing on any single application was related to all of the applications, and requested that the Board panel consider all of the relevant information when making its decision on any of the applications.

1.2 Hearing

The applications were heard on 23 and 24 January and 1 February 1990 at a public hearing in Calgary, Alberta, before Board Members E. J. Morin, P.Eng., B. F. Bietz, Ph.D., and Acting Board Member, M. J. Bruni.

The following table lists the participants at the hearing.

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Victor R. Durish (Mr. Durish) J. K. Farries, P.Eng.	V. R. Durish
Seascape Oil & Gas Ltd. (Seascape) D. Venturo	R. M. Maxwell
Energy Resources Conservation Board staff A. L. Larson, P.Eng. R. L. Paulson, C.E.T. V. J. Vogt	

The Board panel elected to hear the issue of the well licence transfer first, compulsory pooling second, and the assignment of the pipeline licence last. In this regard the applications were presented in the following order: Applications 891646, 891184, 891647, 890978, and 890979.

1.3 Background

The Board issued Well Licence No. 75430 in May 1979 to Lobell Oil & Gas Ltd. (Lobell) upon application by its company president, Mr. Durish. Lobell drilled the 13-21 well that same month to the Leduc Formation, and by doing so earned a 50 per cent undivided interest in the well and any production through the well. Its other partner in the drilling spacing unit was White Resource Management Ltd. (White).

In mid-1981, Lobell sold the well and its earned interest in section 21 to WRM (a sister company of White) and its partners. As a result of this sale, Lobell transferred Well Licence No. 75430 to WRM. The Board completed the transfer on 27 July 1981.

In 1981, WRM constructed an 88.9-mm O.D. Level 1 sour gas pipeline in accordance with Board Pipeline Licence No. 19216. The first leg of the pipeline travelled from the 13-21 well site to connect with Gulf's Malmo pipeline located approximately 1 mile to the west in legal subdivision 15 of section 20, township 43, range 22, west of the 4th meridian. In 1983, WRM extended the pipeline to Gulf's gas battery located in legal subdivision 10 of section 29, township 43, range 22, west of the 4th meridian. Area residents had complained of sour gas odours emanating from the dehydrator located on the first leg of the pipeline. Construction of the second leg of the pipeline eliminated the need for the dehydrator and thus eliminated the odour complaints.

The well commenced sour gas production from the Malmo D-3 B Pool in December 1981 and produced some 11.5 million cubic metres of gas over the next 4 years until November 1985 when Gulf shut in the pipeline at its battery inlet because of a dispute with WRM over transportation and processing fees.

With the shutting in of the 13-21 well, WRM and White ceased payment of any monies to the freehold royalty interest owners within the section, including Mr. Durish. As a result of this non-payment, Mr. Durish began legal proceedings against White to invalidate White's leases with him in section 21. A lower court judgement of 2 September 1987 found for Mr. Durish; the judgement was appealed by White.

The decision on the appeal was rendered on 15 November 1988 and the appeal was denied. The court decision effectively terminated all of White's freehold leases within the section, which included all but a 25.5-acre Crown tract located in the southeast quarter of the section. However, by the time of the original court decision (September 1987), White had already obtained new leases with all of the freehold owners in the section except for Mr. Durish. The White leases were subsequently transferred to Seascape.

Following the shutting in of the 13-21 well, WRM experienced increasing financial difficulties and eventually became incapable of carrying out its duties as operator of the well. In light of WRM's financial difficulties, a majority of the working interest owners in the well appointed Seascape the operator to replace WRM. The Board, upon application by WRM, transferred the well licence to Seascape at the end of October 1987. At about the same time, WRM ceased being a viable company with the resignation of its company officers.

2 ISSUES

The Board considers the issues to be

- the transfer of the well licence,
- the need for a compulsory pooling order, and
- the assignment of the pipeline licence.

3 TRANSFER OF THE WELL LICENCE

3.1 Views of Mr. Durish

Mr. Durish divided the tract ownership within section 21 as follows:

	TRACT	LESSOR	AREA
1.	North half and 134.5 acres in southeast quarter	Victor R. Durish	454.5 acres
2.	25.5 acres in south-east quarter	Crown	25.5 acres
3.	North half of southwest quarter	8 freehold owners of undivided interests	80.0 acres
4.	South half of southwest quarter	One freehold owner	80.0 acres

Mr. Durish stated that, pursuant to section 13 of the Act, he should be named the licensee of the 13-21 well. Mr. Durish based this statement on the fact that the 13-21 well is located within his freehold mineral holdings and that he is the major mineral interest owner of natural gas within the section, including some 71 per cent of undisputed ownership, described in tract 1 above, and of a further 23 per cent of disputed ownership between Seascape and himself in the form of competing leases with most of the freehold owners in the southwest quarter, described in tracts 3 and 4 above.

3.2 Views of Seascape

Seascape maintained that it is the rightful licensee of the 13-21 well, and as such disagreed with Mr. Durish's claim that he ought to be the licensee based on his mineral ownership within the section. Seascape did not disagree with Mr. Durish's division of the tract ownership, but did disagree with Mr. Durish's interpretation of the current leasing agreements. Seascape submitted that the transfer of the well licence is not governed by section 13 of the Act as Mr. Durish maintained, but by section 18.

Seascape asserted that section 18 provides that the Board, before consenting to a transfer of well licence from a company that has been dissolved, must satisfy itself that the party that agrees to accept the well licence has the right to receive it.

Seascape argued that the mineral holdings within section 21 held at the time of the October 1987 transfer by its predecessor in interest, White, the sister company to WRM, also gave WRM the right to transfer the 13-21 well licence to Seascape. At that time, the appeal of the Court decision which cancelled White's leases with Mr. Durish had not been heard, and therefore Seascape submitted that there was a very real possibility that White still held all of the mineral interests within the section. As well, irrespective of the eventual upholding by the appeal court of the decision against White, Seascape maintained that it still held uncontested leases covering the entire southwest quarter of section 21, as no litigation against these leases had been initiated.

Finally, Seascape argued that it was the rightful licensee of the well based on the fact that it held the surface lease for the well. Seascape noted that as the surface leaseholder it has been paying monies to the surface owner in accordance with the stipulations in the lease, and has expended additional funds for weed control at the well site.

4 NEED FOR A COMPULSORY POOLING ORDER

4.1 View of Mr. Durish

Mr. Durish stated that he and Seascape were unable to reach a voluntary operating and mineral-sharing agreement for production from section 21; therefore, Mr. Durish believed that there is a need for a compulsory pooling order. Mr. Durish added that a timely decision is required because gas reserves beneath section 21 are being drained as a result of production through wells from off-setting drilling spacing units.

Mr. Durish contended that as a judgement creditor for the now defunct WRM, a court of law may show him to be the rightful owner of the 13-21 well and its facilities; however, he recognized that the Board has no authority to determine questions of ownership. Notwithstanding this, Mr. Durish believed that a Board-issued pooling order should name him as the operator of the 13-21 well based on the fact that the well is located on land within his mineral ownership and that he is the majority mineral owner within the section, holding in excess of 71 per cent of uncontested ownership and a further 23 per cent of contested ownership.

Mr. Durish described the contested ownership as competing leases he has with Seascape for 15/16 of the freehold ownership within the southwest quarter. It is because of this contested ownership that Mr. Durish believed a pooling order pursuant to section 78 of the Act is appropriate. Mr. Durish submitted that a court of law will show Seascape's leases within the southwest quarter to be invalid.
Mr. Durish stated that until the mineral ownership of the southwest

quarter is established, the monies that accrue to those tracts as a result of production from the Malmo D-3 B Pool through the 13-21 well, less the freehold royalty payments, should be paid to the Provincial Treasurer in accordance with section 78 of the Act.

Mr. Durish noted that the 13-21 well was used for sour gas production for some 4 years, then sat unused for a further 4 years. Based on this, Mr. Durish contended that the integrity of the well and its facilities were in question, and an engineering evaluation would be required before it could be determined whether the well physically or economically could be placed back on production. Mr. Durish stated that if he were granted the pooling order and named as the operator, he would be prepared to complete the engineering evaluation and carry out the appropriate work required to put the well back into production; or, in the alternative, if he found the well unsuitable for further production, he would be prepared to properly abandon it. Mr. Durish added that if he became operator, he also planned to approach Gulf, as operator of the Malmo D-3 B Unit, to have section 21 included in the Unit. Mr. Durish stated that if Gulf agreed to the Unit expansion, there was a chance that the 13-21 well would never have to go back on production since Gulf would be able to capture the reserves under section 21 through currently producing Unit wells.

Mr. Durish submitted that individual tract owners should not be responsible for any share of the original drilling costs of the 13-21 well. Mr. Durish maintained that original drilling costs are no longer an issue because the parties now involved in the well differ from those involved in the well during the time it was drilled. It was Mr. Durish's opinion that the original costs incurred in drilling and completing the well were recovered by Lobell in the sale of its interests to WRM. Mr. Durish added that the net revenue obtained during the 4 years the well was on production was sufficient to recover any drilling costs. Moreover, Mr. Durish argued that it is not the intent of the pooling legislation to allow parties, such as Seascape and its partners in this matter, to receive well costs for a well that was acquired in a business venture outside the exploration and development of oil and gas. Mr. Durish recognized, however, that certain costs which would qualify as drilling costs within the definition given in the Act's pooling legislation may accrue in placing the well back on production. Mr. Durish had no objection to these drilling costs being allocated back to the tract owners. Mr. Durish recognized that the well may have a value, but believed that value to be more in the context of a market value which would be determined by a court of law when it decided the ownership question.

Mr. Durish also believed the allocation of a penalty to drilling costs to be a non-issue. Mr. Durish stated that in his opinion the penalty that the Board would be allowed to impose in accordance with section 72(5) of the Act was intended to apply only to original drilling and

completion costs. Thus, because Mr. Durish did not believe that the participants in the well should, as a result of a Board-issued pooling order, have to pay original well costs, it followed that no penalty should be applied.

Mr. Durish took exception to Seascape's claim that drilling costs ought to include monies expended to construct facilities beyond the wellhead that would be used for the purpose of gathering and processing the gas. Mr. Durish stated that it was his opinion that the industry accepted that well costs included only costs incurred up to the wellhead. Mr. Durish contended that it was also the intent of section 72 of the Act to have drilling costs for purposes of a Board-issued pooling order determined in the same way. Mr. Durish added that he knew of no provision within the Act that would allow the Board the authority to determine the costs of facilities used to gather and market the production and allocate it back to the tract owners.

Finally, Mr. Durish stated that the allocation of costs and revenues to each tract owner within section 21 as a result of gas production from the Malmo D-3 B Pool through the 13-21 well should be on an areal basis.

4.2 Views of Seascape

Seascape stated that it had been unsuccessful in negotiating a voluntary mineral-sharing agreement with Mr. Durish that would allow the recommencement of production operations through the 13-21 well; consequently, Seascape believed that there is a need for a compulsory pooling order. Seascape's division of the tracts within section 21 agreed with that of Mr. Durish.

Seascape stated that it is a tract owner within the drilling spacing unit by virtue of its leases with the freehold owners in the southwest quarter and its lease with the Crown for a 25.5-acre tract situated in the southeast quarter. It is on this basis of tract ownership, and the fact that it is the licensee of the 13-21 well, that Seascape requested that the Board issue a compulsory pooling order and name it the operator of the well within the order.

Seascape took exception to Mr. Durish's claim that he has competing leases with Seascape for the freehold mineral ownership in the southwest quarter. Seascape contended that Mr. Durish's leases are top leases, and only become valid if a court of law determines Seascape's leases to be invalid. Seascape added that there is no existing court action to declare its leases within the southwest quarter to be invalid. Because of this, Seascape maintained that a pooling application pursuant to section 78 of the Act is improper.

Seascape argued that drilling costs for purposes of a Board-issued pooling order are valid whether or not it is appointed the operator of the well. Seascape maintained that the parties currently involved in the well paid a consideration for that involvement and ought to be reimbursed.

Seascape stated that well costs pursuant to the Act should include some $485 000 of initial drilling costs and a further $549 672 of costs incurred between 1981 and 1984 to complete and equip the 13-21 well for production. Seascape also believed that if a tract owner does not pay its proportionate share of well costs within 60 days of a judgement by the courts determining ownership, then the tract owner should be subject to a 50 per cent penalty applied to its share of well costs.

Seascape agreed with Mr. Durish that the integrity of the well was in question at this time, but stated that it was prepared to obtain a technical evaluation of the well and proceed with the necessary work required to place the well back on production. Seascape added that it was also prepared to properly abandon the well and reclaim the well site when necessary. Seascape stated that it has the finances to operate and abandon the well.

Finally, Seascape agreed with Mr. Durish that the allocation of costs and revenues to each tract within section 21 as a result of gas production from the Malmo D-3 B Pool through the 13-21 well should be on an areal basis.

5 ASSIGNMENT OF THE PIPELINE LICENCE

5.1 Views of Mr. Durish

Mr. Durish contended that if he is successful in his bid to obtain the well licence and to be named operator in the pooling order, then the next step would be to assign him the pipeline licence in order that he may produce the well. Mr. Durish stated that he has some claim to the pipeline ownership through his interest in the assets of WRM by virtue of his position as judgement creditor. In addition, Mr. Durish argued that he is the majority owner of the gas to be produced and transmitted through the pipeline. Mr. Durish stated that if he is unsuccessful in his bid to obtain the 13-21 well licence and to be named operator in the pooling order, then assigning the pipeline licence to him would not be beneficial.

Mr. Durish stated that he has the ability to accept both the financial and technical obligation of pipeline ownership. He stated that if he were assigned the pipeline licence he would assume responsibility for obtaining an engineering assessment of the integrity of the pipeline and surface equipment. He agreed to also assess the operational problems, as well as ensure that all of the ERCB regulations are adhered to before putting the line back in operation. Mr. Durish finally committed to abandoning the pipeline if he found it unsuitable or unnecessary for operation.

5.2 Views of Seascape

Seascape stated that it should be assigned the pipeline licence because the original licensee, WRM, assigned the pipeline to Seascape in 1987. However, Seascape agreed that the assignment was never registered with the Board.

Seascape stated that it has been acting as licensee for the past 2 years. Seascape stated that during this time the pipeline has been shut in and it has done no work to the pipeline, but has paid the pipeline taxes. Seascape added that it has the easements for the pipeline right of way. Seascape also stated that it has no emergency procedure operating or maintenance manuals, and has not undertaken any procedure to suspend the pipeline in an appropriate manner.

Seascape argued that if it retained the well licence and was granted the pooling order, then it would only be reasonable to assign it the pipeline licence. Seascape contended that it is still the owner of the pipeline and has monies invested in it. Seascape believed the pipeline has a value and expects anyone else who is assigned the licence to pay for the pipeline. Seascape agreed that it made sense to grant the well licence, pooling order, and pipeline licence to the same party.

Seascape maintained that it is financially capable of operating the pipeline and agreed to retain an engineering firm to undertake technical matters. Seascape committed to completing an engineering assessment of the integrity of the pipeline and the suitability of the surface equipment. It also agreed to assess the operating problems, as well as ensure that all ERCB regulations are adhered to before the pipeline is put back in operation. Seascape stated that if the pipeline is found unsuitable or unnecessary for operation, it would properly abandon it.

6 VIEWS OF THE BOARD

The Board believes that its decision on these applications does not hinge on the pipeline issue as the pipeline is an "orphan", since WRM, the current licensee of the pipeline, is a defunct company. Accordingly, either party could be assigned the licence depending on which requires it to produce the gas reserves underlying section 21. Similarly, the pooling order could be assigned to either party depending on who has the right to produce the well through which the gas reserves will be obtained. Accordingly, the Board concludes that the issue of the assignment of the well licence is the key to its decision.

In considering the issue of the well licence, the Board decided during the hearing that it would, pursuant to section 42 of the Energy Resources Conservation Act, conduct a review of the October 1987 well licence transfer from WRM to Seascape. The Board notes that circumstances, and particularly the Board's understanding of mineral

ownership within the section, have changed considerably since that time. The Board believes that had it known in October 1987 of the outstanding litigation in progress regarding the validity of the leases within section 21, its position may have been to defer its decision on the application for well licence transfer pending the outcome of the appeal.

The Board notes that the well is currently situated, and has been since at least the November 1988 court of appeal decision, on a quarter section drilling spacing unit for which the mineral holdings, both oil and gas, are completely owned by Mr. Durish. The Board also notes that Seascape has no pooling agreement in place that would combine all of the tracts within the section as a unit for the purpose of gas production. Moreover, the Board is aware that if the 13-21 well were capable of oil production or if a gas production test were required and Mr. Durish were the licensee of the well, Mr. Durish would have the right to produce through the well within the quarter section drilling spacing unit for either of these purposes without any agreement with any other mineral owners in the section. However, he also could not commence commercial gas production until a pooling agreement was in place.

Section 13 of the Act requires that a person applying for a well licence be entitled to produce the well. The Board believes that this requirement applies to either an application for a new well or to the transfer of an existing well licence. Accordingly, since Seascape does not have the right to produce from the well within the quarter section drilling spacing unit and Mr. Durish does, the Board will rescind its 28 October 1987 consent to the transfer of the well licence from WRM to Seascape, and direct that the well licence be transferred to Mr. Durish. Further, the Board believes that such a finding is in keeping with section 4(c) of the Act to provide for economic, orderly, and efficient development in the public interest.

It follows from the well licensing decision that the Board believes the pooling order and the assignment of the pipeline licence should be granted to Mr. Durish, or to his corporate entity.

In making its decision to issue a pooling order, the Board notes the on-going, but unsuccessful, attempts between the parties to reach a voluntary settlement of the issues. For this reason the Board believes there is a need for a compulsory pooling order.

The Board agrees with the definition of the tracts within section 21 as given by both parties, and is satisfied from the evidence that there is a dispute as to lease ownership for the two tracts of freehold minerals within the southwest quarter of section 21. In this regard, the Board believes that a pooling order pursuant to section 78 of the Act is appropriate. As such, the Board expects the revenues attributed to the two tracts in the southwest quarter, less the appropriate costs including the royalties which are to be paid to the freehold mineral owners, shall be remitted to the Provincial Treasurer in accordance with section 78 of the Act pending a settlement of the ownership dispute.

The Board believes that a compulsory pooling order requiring payment of the costs of drilling and completing a well is intended to be reimbursement for the actual costs incurred by the recipient. It is effectively a reimbursement by those parties who would benefit by production through the well to those parties who assumed the costs and risks associated with drilling and completing the well.

The Board has determined that none of the parties before it directly incurred the actual costs and risks of drilling and completing the 13-21 well, and therefore should not be reimbursed for costs and risks not assumed. For the same reason the Board believes the application of a penalty against drilling and completion costs would be inappropriate.

The Board recognizes, however, that costs that should be considered drilling costs in accordance with section 75 of the Act may accrue as a result of work to be done on the well in an attempt to get it back on production. The Board believes that tract owners should be responsible for their share of well costs. Any order, therefore, will provide for the recovery of these well costs, but with the understanding that these will only be those well costs required to allow production to resume through the 13-21 wellbore. In addition, any reasonable costs incurred by Seascape for maintenance of the shut-in well should be shared by the tract owners.

The Board notes that Seascape's definition of drilling costs included monies spent for facilities required to gather and market the gas. Given the definition of drilling and completion costs in section 75 of the Act, wherein it states that the actual cost of drilling a well shall include the cost of drilling the well to and completing it in the formation named in the order, the Board concludes that the monies spent to gather and market the gas would not qualify as drilling costs for the purposes of a Board pooling order.

The Board agrees with both applicants' request that the allocation of costs and revenues to tracts within section 21 as a result of gas production from the Malmo D-3 B Pool be on an areal basis.

In granting the well licence and pipeline licence to Mr. Durish, the Board expects him to confirm in writing that he will satisfy his commitment to

- retain an engineering firm to provide operating expertise and develop corporate emergency response planning,

- retain adequate and appropriate insurance coverage,

- complete an engineering assessment of the integrity and suitability for operation of the 13-21 wellbore, the surface equipment, and the pipeline,

- ensure that the well, surface facilities, and pipeline meet ERCB regulatory requirements prior to the commencement of production operations, and

- properly abandon the well and the pipeline when required or directed.

Finally, in granting Mr. Durish the well licence and the pipeline licence, the Board makes no judgement on the question of ownership of the well and its facilities, or any monetary value that they may have. The Board notes that to be the holder of a well licence or a pipeline licence, the licensee does not have to be the owner of either. Should either applicant consider the ownership and value of the well and its facilities an issue then the Board submits that those matters are outside its jurisdiction and therefore more properly determined by another forum.

7 DECISION

The Board will

- assign Well Licence No. 75430 to Mr. Durish or to a corporate entity he may establish to accept the licence,

- with the approval of the Lieutenant Governor in Council, issue an order specifying that

  - all tracts within section 21 of township 43, range 22, west of the 4th meridian, be operated as a unit to permit the production of gas from the Malmo D-3 B Pool through the well, LOBELL ET AL MALMO 13-21-43-22;

  - Mr. Durish, or his corporate entity, be designated the operator of the well and be responsible for the well and for all completion, production, and abandonment operations of the well;

  - the allocation of costs and revenues associated with drilling, operating, or abandoning the well be on an areal basis, with each tract's share being in the same proportion as the area of each tract is to the total area of the drilling spacing unit;

  - that the ownership of two tracts within section 21, described as the north half and the south half of the southwest quarter of the section respectively, be considered to be in dispute in accordance with section 78 of the Act; and

  - in accordance with section 78 of the Act, that Mr. Durish sell the share of production to which the disputed tracts are allocated, pay the appropriate share of expenses attributable to those tracts out

of their share of proceeds, and pay any balance to the Provincial Treasurer pending a settlement of the ownership dispute; and

- assign Pipeline Licence No. 19216 to Mr. Durish, or to a corporate entity that he may establish to accept the licence.

DATED at Calgary, Alberta, on 29 March 1990.

ENERGY RESOURCES CONSERVATION BOARD

E. J. Morin, P.Eng.
Board Member

B. F. Bietz, Ph.D.
Board Member

M. J. Bruni
Acting Board Member

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ENERGY RESOURCES CONSERVATION BOARD

Calgary Alberta

CHESAPEAKE RESOURCES LTD.
APPLICATION FOR A WELL LICENCE
WHITEMUD AREA

Decision D 90-3
Application 891846

1 INTRODUCTION

1.1 Application and Interventions

Chesapeake Resources Ltd. (Chesapeake) applied, pursuant to section 2.020 of the Oil and Gas Conservation Regulations, for a licence to drill a well to be known as CHESAPEAKE ET AL WHMUD 16-12-51-25 (the proposed well), to obtain oil or gas production from the Ellerslie Formation. The proposed well would be drilled in legal subdivision 16 of section 12, township 51, range 25, west of the 4th meridian, on a subdivision lot owned by Hornbeck Farms Ltd.

Interventions opposing the application as filed were submitted by Mr. and Mrs. Louis and Evelyn Sabo (the Sabos) and the Royal Canadian Alpaca Ranch (the Ranch). In addition, at the hearing, an intervention was filed by Mr. Mario Bevilacqua.

1.2 Hearing

A public hearing of the application was originally scheduled for 30 January 1990. Prior to that date, the Board received a request from the Ranch for a postponement of the hearing to allow time for the Ranch's expert witnesses to prepare their submissions. The Board re-scheduled the hearing to commence 28 March 1990.

The public hearing of the application was held in Nisku, Alberta, on 28, 29 and 30 March 1990 before Board Members J. P. Prince, Ph.D., B. F. Bietz, Ph.D., and Acting Board Member J. D. Dilay, P.Eng. (the Board). At the outset of the hearing it was agreed by all parties that a site visit to the Ranch and the proposed well location would be appropriate. The site visit was conducted on 28 March 1990 and was attended by Chesapeake, the Ranch, the Sabos, the Board, and Board staff.

The attached figure shows the proposed well location, the subdivision, the oil and gas target areas, and certain features of the area.

2 BACKGROUND

The proposed well would be located in the Whitemud area, adjacent to the southern boundary of the city of Edmonton. Oil and gas exploration has occurred here since the late 1940s with approximately 70 wells being drilled within a 7-kilometre (km) radius of the proposed well. Of these, approximately 82 per cent were drilled prior to 1980, 86 per cent have been abandoned, 10 per cent are gas, and 4 per cent are either oil or undesignated. The majority of these wells are located to the west and north of the proposed well. The Whitemud area has not been designated by the ERCB as an oil or gas field and the allowed well spacing for this area is one gas well per section and one oil well per quarter section (Board spacing unit order SU 1088).

Because of the proximity of the proposed well to a rural subdivision and adjacent residences, Chesapeake provided notification of its plans to drill the well to landowners and residents in the area. Chesapeake also held an "open house" on 23 October 1989 to provide information to landowners and residents on the drilling and production of the proposed well and to identify any concerns they may have. The concerns the residents expressed included the potential for odours, noise from drilling and production operations, increased traffic, visual aesthetics, reduction of property values, and adverse impacts to livestock. Subsequent to the open house, correspondence was received by the Board from local residents and landowners expressing opposition to the proposed well.

The Ranch is located to the southwest of the proposed well with the closest point of the Ranch property being approximately 150 metres (m) from well centre. The Ranch has 30 alpacas on site, with an estimated value of $600 000 to $900 000, and 6 more in quarantine awaiting importation. It has developed its facilities specifically for the raising of alpacas. Those facilities include a large enclosed, heated shelter, small open shelters that provide cover for the alpacas when they desire it, and a 13-strand electric fence surrounding the Ranch and paddock areas.

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Chesapeake Resources Ltd. (Chesapeake) K. F. Miller	J. D. McCormick Y. A. Rivard, P.Geol. L. Frank, P.Eng. of HFP Acoustical Consultants Ltd. J. B. Long, P.Eng. of The Barlon Engineering Group Inc. W. L. Franklin, Ph.D. of Iowa State University
Royal Canadian Alpaca Ranch (the Ranch) J. N. Slavik	F. A. Schnelle E. H. Bolstad, P.Eng. of Bolstad Engineering Associates Ltd. J. G. Ferguson, Ph.D. of the Western College of Veterinary Medicine
E. and L. Sabo (the Sabos)	E. Sabo L. Sabo
M. Bevilacqua	M. Bevilacqua
Energy Resources Conservation Board staff C. S. Richardson S. Baron, P.Eng. R. Wright, P.Eng.	

The Sabo property is located directly west of the proposed well with its closest point being approximately 80 m from the west boundary of the proposed well lease and access road. The Sabos reside 420 m from the well centre and they own a rental home (the Oranchuk residence) that is 170 m from the well centre. Approximately 50 m of poplars and associated understory vegetation are located between the Sabo property and the proposed well site and access road.

The quarter section of land containing the well site is subdivided into ten parcels. Eight are residential acreages and two are municipal reserve parcels.

3 ISSUES

The Board considers the issues with respect to the application to be

- the need for the well,
- the effects of drilling the well on the neighbouring residences, and
- the impact of drilling on the Ranch.

4 NEED FOR THE WELL

4.1 Views of the Applicant

Chesapeake submitted that it had entered into an agreement with Amerada Minerals Corporation of Canada Ltd., the holder of the Alberta Crown petroleum and natural gas lease for section 12-51-25 W4M (section 12), whereby the drilling of the proposed well would earn it an interest in the production of any oil or natural gas from section 12. It estimated that (if the well were successful) there would be a 70 per cent chance of an oil well and a 30 per cent chance of a gas well. It further submitted that, based on an estimated 23 850 cubic metres (m^3) of oil per oil well spacing unit or potential gas reserves of 56 000 000 m^3 per gas well spacing unit, royalties payable to the Alberta Crown would be approximately $500 000 for an oil well or $800 000 for a gas well. Chesapeake stated that the proposed well would be very significant to its business and that the drilling of the well would further the Board's mandate for conservation of the resource.

4.2 Views of the Interveners

The Ranch submitted that the value of its alpacas, the Ranch itself, and the revenues that would be generated from the growth of the Ranch would greatly exceed the value of the proposed well to either Chesapeake or the Province of Alberta. It stated that its significant investment and the future development of the Ranch would be in jeopardy because of the adverse impacts that could be imposed on it by the drilling of the proposed well. It believed that the need for the proposed well did not outweigh the impacts it would cause.

4.3 Views of the Board

The Board notes that Chesapeake's geological interpretation was not disputed. In considering the need for the well, the Board must consider the rights of the mineral owner, the leaseholder, the province, and the owner of the surface rights. The leaseholder has the right to explore for and develop resources subject to its compliance with the Oil and Gas Conservation Act and other legislation. The mineral owner has a right to benefit from production of its resource, and the people of the province have a right to benefit from taxes or royalties associated with production of the resource. The Board accepts that Chesapeake has the right to explore for and develop any oil or gas reserves that may underlie section 12 and that production from the proposed well would generate significant economic benefits. If reserves exist under the section, there is no other existing well in the section capable of draining the reserves. Therefore, the Board believes that there is a need for this well. If the adverse effects of the well can be mitigated enough to make them acceptable, the Board would not deny the application on the basis of need.

5 EFFECTS OF DRILLING THE WELL ON THE NEIGHBOURING RESIDENCES

5.1 Views of the Applicant

Chesapeake submitted that it had chosen its surface location for the proposed well having special consideration for the proximity of the nearby residential subdivisions. It stated that it chose to directionally drill the well to the common oil and gas target area of the northeast quarter of section 12 from a surface location approximately 170 m north of the bottom-hole location. This site was selected since it would be less disruptive to area residents than drilling directly above the bottom-hole location. The decision to directionally drill adds approximately \$20 000 to the cost of drilling the well.

Chesapeake stated that in consideration of the Sabos' concerns it had discussed with its surface lessor, Hornbeck Farms Ltd., the possibility of moving the well site and access road farther east, away from the Oranchuk residence. The lessor was opposed, however, to relocation of the well site or access road as this would sterilize the small portion of land that would be left on the west side of the proposed well location and access road. It was the lessor's requirement that the lease and access road remain on the west boundary of its property.

Chesapeake submitted that the surrounding tree cover at the proposed surface location would effectively reduce noise and visual impacts and would completely screen any production facilities. It stated that it would monitor noise levels at the Oranchuk residence during the drilling of the well and would adhere to the ERCB Noise Control Directive ID 88-1 (the noise directive). Chesapeake committed to properly fence the well site, have a locked gate at the lease road approach, equip the pumping unit with an electric drive motor, install a blowout preventer, and install high- and low-pressure shut-down devices. It further committed to incinerate gases using a low level non-visible flare, to berm the lease to contain any spilled fluids, and to install vapour recovery equipment on tankage and the separator.

At the hearing Chesapeake expanded on how some of the operations would be conducted. It would select a quiet drilling rig (see Section 6) in consultation with the ERCB and, if necessary, the Ranch. Drilling was estimated to require 8 to 10 days, plus 5 to 6 days to complete and test the well. If oil was discovered, the pumping unit would be propane powered for an initial test period of approximately 60 to 90 days; thereafter any permanent unit would be powered by electricity. Tanker trucks would be used to haul oil from the facility and, based on an estimated production rate of 8 m^3 per day of oil, a tanker truck would be required approximately once every 4-5 days. If the well contained gas, Chesapeake would shut the well in until such time as it was able to tie it into a gas pipeline.

Chesapeake stated that it believed that through its meetings with the Oranchuks, the current residents in the rental home owned by the Sabos, any concerns they had were addressed. Chesapeake believed that the commitments made to alleviate the Sabos' concerns and the additional commitments made at the

hearing would further reduce any impacts on the Oranchuks from the drilling or production of the proposed well.

5.2 Views of the Interveners

The views of the Ranch in regard to the proposed well were primarily directed towards impacts on its alpacas and the subsequent economic effects. This issue is addressed separately in Section 6.

The Sabos expressed several concerns respecting the drilling and operation of the proposed well. They stated that they owned the home located approximately 170 m west of the proposed well and that the proximity of the well would affect the potential to rent the home in the future. They were concerned that drilling noise would affect the current renters of the home. They were also concerned about odours from production facilities and trucking, visual impacts from the drilling rig and production facilities, and contaminants from drainage or spills from the well. The Sabos suggested that, if the well location and access road were moved approximately 100 m east, this would alleviate the majority of their concerns. The Sabos also requested that Chesapeake inform them prior to drilling into the potentially sour Ellerslie Formation.

Mr. Bevilacqua expressed concern for the potential for odours from the proposed well and impacts that may occur if Chesapeake planned further drilling in the area. He noted that his land is located east of the proposed well in the adjacent section and that he planned to build a home there in the near future.

5.3 Views of the Board

Having established the need for the well, the Board also recognizes that the well is exploratory in nature and may or may not be successful. If it is successful the Board must consider what impact it may have on the neighbouring environment and what mitigative measures may be available to reduce that impact. If it is not successful, the applicant has stated that no further exploration in the immediate area would be contemplated. That in itself may be valuable information for both the residents and the Ranch. The Board also notes that, in general, it is more desirable to develop resources that are close to populated areas before the advancing population makes that development even more difficult.

The Board must also consider how the residents and other property owners would be affected by the proposed well, what mitigative measures are available to reduce that impact, and whether or not these measures would be adequate to reduce impacts to an acceptable level. The potential environmental, economic, and social impacts which cannot be mitigated must then be weighed against the need for the well and the potential benefits from producing the well.

The Board notes that, in response to local concerns, Chesapeake has opted to directionally drill the well from a surface location that should be less intrusive than a vertical hole location, at an additional cost of $20 000. The Board believes that drilling and completion operations for this well will be of reasonably short duration. Further, Chesapeake would conduct sound monitoring at the Oranchuk home, would adhere to the requirements of the noise directive, and would reduce drilling noise by the choice of a rig that has effective noise attenuation and tuned silencers.

Respecting the Sabos' proposed relocation of the well 100 m east, Chesapeake has been restricted from locating the well and access road farther east by its lessor, Hornbeck Farms Ltd. Even so, if the Board determined that a proposed location was not acceptable, that the applicant had not adequately considered alternative locations, and that acceptable alternative locations existed, the Board could deny that application without prejudice to any further application the company may wish to make. In this case, however, Chesapeake has considered alternative locations and has chosen a surface location to attempt to minimize impacts on area residents. Its location is technically and economically feasible and there are no other technically and economically feasible surface locations that would further minimize impacts on some residents and landowners without increasing impacts on other residents and landowners. The Board believes that the proposed location is appropriate provided that its impacts can be reduced to acceptable levels. Although some increase in noise and activity will occur during the drilling of the well, the mitigative measures proposed by Chesapeake will help keep that increase small. The Board believes it can set further conditions that will ensure that the impact of drilling the well, over the relatively short period drilling will occur, will be reduced to an acceptable level.

The Board has also reviewed the potential adverse impacts on the Sabos, the Oranchuk residence, and Mr. Bevilacqua that could result from the operation of the proposed well if drilling is successful and has considered the mitigative measures proposed by Chesapeake. If a successful well is developed,

Chesapeake has committed to:

- install vapour recovery systems on tankage, separator, and loading facilities,
- electrify any permanent oil production facility,
- berm the lease,
- install high- and low-pressure shut-down devices,
- install blowout prevention equipment on the producing wellhead,
- construct proper fencing,
- install a locked gate at the access and approach,
- adhere to good housekeeping practices.

Having regard for these measures, the Board believes the proposed well can be operated without seriously affecting the Sabos, the Oranchuks, or Mr. Bevilacqua. The Board also notes that any proposed production operations at the proposed well would be subject to future applications and reviews by the Board. Any persons that may be affected by those applications would at that time have further opportunity to present their concerns to the Board for its consideration.

6 IMPACT OF DRILLING ON THE RANCH

6.1 Views of the Applicant

Chesapeake recognized that the Ranch raises a very valuable and exotic type of livestock not common to North America. It submitted that it had considered this throughout its planning of the well and endeavoured to solicit information from informed sources with respect to the disposition of the alpacas and their reaction to various stimuli. Dr. Franklin, on behalf of Chesapeake, submitted that in general alpacas are easy-going, stoic, domestic animals that are easy to care for and raise. They are highly adaptable to a wide variety of environmental conditions with the exception being a susceptibility to heat stress. They are well known for their ability to adjust and habituate to sudden strange noises and situations and to remain calm when confronted by heavy equipment and machinery. It was Chesapeake's position that, based on the current sound environment of the Ranch, the expected noise levels from the proposed drilling program and/or the operation of the well would not stress or in any other way adversely affect the alpacas.

Respecting expected sound levels from the rig, Chesapeake did not believe that monitoring sound levels at the Ranch would be necessary; rather it believed that sound monitoring at the nearest residence would be in keeping with the Board's noise directive. It believed that good quality silencers and the selection of a quiet rig were sufficient to allow it to remain below the 55-decibel (dBA) nighttime and 65-dBA daytime permissible sound levels at the Oranchuk residence.

Chesapeake stated that it would retain a qualified veterinarian to monitor the alpacas before, during, and after the drilling operation, and it would consult with its sound expert in the selection of a properly noise-attenuated rig and tuned silencers. It also would utilize a non-visible flare on production operations, with visual impacts further reduced by its decision to locate the well farther north into the bush. It believed that, based on the mitigative measures it proposed and the natural disposition of alpacas, it would not be necessary to move the alpacas to an alternative boarding facility for the duration of the drilling and completion of the well and that moving the animals would potentially induce more stress than the proposed drilling operation.

6.2 Views of the Ranch

The Ranch stated that its current location was chosen because it provided a stable, healthy environment for the alpacas. It submitted that it is not in close proximity to traffic corridors, there is little local activity that may cause stress to the alpacas, and the effect of nearby air traffic is negligible as the sound of approaching aircraft is of a gradually increasing constant frequency to which the alpacas are adapted. The Ranch submitted that it has enjoyed a 100 per cent reproductive success rate with its alpacas to date.

The Ranch believed that if the proposed well were drilled, the noise in particular, plus lights and fumes from the drilling rig, could cause stress to the alpacas. A primary concern regarding the proposed drilling operation was the effects on the alpacas from sudden noise such as pipe clanging and change in pitch from the rig motors. It was the Ranch's position that such stress would produce negative effects on the health and reproductive capacity of the herd, including absorbed pregnancies, abortions, still-births, and reduced lactation (milk production).

Dr. Ferguson, on behalf of the Ranch, stated that there is no substantial documentation on the alpacas' behaviour or physiological responses to stresses but that it was possible to extrapolate the alpacas' likely stress responses from knowledge and studies of other

animals. He believed that stressors which can act on alpacas include temperature changes, strange sights, sounds, odours or touches, muscle strain during restraint procedures, close confinement, thirst, and hunger. He further stated that both intense and lower levels of chronic stresses create a possibility of producing deleterious effects on the animals.

The Ranch did not believe that the Board's noise directive was directly applicable to its situation because of the unique nature of alpacas, and because the noise directive was designed to address noise impacts on humans, not animals. The Ranch stated that a permissible sound level of 55 dBA would increase the general sound environment significantly from the current ambient level. As a result, the Ranch proposed an "ambient plus adjustment" noise criteria for the drilling of the well. It suggested that the ambient sound level be measured and a 3-dBA equivalent sound level (Leq) allowance be made for the drilling rig. The 3-dBA Leq was chosen as this represented an approximate doubling of the ambient acoustic intensity. The Ranch further requested that sound monitoring be conducted at the edge of the Ranch property near the proposed well location and that if drilling noise occurred that exceeded a predetermined permissible sound level, the monitoring equipment be designed to allow determination of what caused the exceedance and that corrective action be taken.

The Ranch stated that it provided information to Chesapeake regarding alternative shelter for the animals. It further submitted estimates on the cost of insurance, fencing, and transportation for the alpacas that totalled approximately $116 000.

6.3 Views of the Board

The Board accepts that the Ranch has a considerable investment in its operation and that its investment may produce a significant return to the Ranch and to the Province.

The Board has considered the expert evidence of both Chesapeake and the Ranch respecting the potential impact of drilling on the alpacas. It considers the sources of potential impact to be noise and, to a lesser degree, light that would emanate from the rig.

From the visit to the Ranch, the Board gained some appreciation for the care and attention given to the alpacas and for their present environment. It was evident that the Ranch has gone to considerable lengths to ensure the alpacas' safety, health, and comfort. The Board also notes that the Ranch is located in proximity to the Edmonton city limits and that a significant level of other activity typical of a country residential setting occurs in the vicinity of the Ranch. It was apparent that farming activities occur in the fields adjacent to the alpacas' pasture and that several neighbouring yards were in close proximity and readily visible from the pasture. It is the Board's observation that the alpacas appear to experience, on both a regular and irregular basis, the sounds of various motors, engines, and other noise sources from various distances, from all directions including from above, and at various intensities. Respecting lights from the proposed drilling operations, it would appear that the alpacas are already adapted somewhat to lights from adjacent farmyards and residences, vehicle and aircraft lights, and lights at the Ranch. Based in large part on the expert evidence presented by both parties, it is the Board's opinion that while severe, extended noise and other similar disturbances can be shown, in general terms, to create stress in domestic animals, there is no evidence which would lead the Board to predict that the alpacas, and therefore the Ranch's commercial viability, would be placed at risk by the drilling, completion, or operation of this well. While the noise and light levels will vary in intensity, they will be from a fixed source, at levels similar to other existing sources, and at a sufficient distance from the animals that it seems very unlikely that the animals will be unable to acclimate.

In coming to this conclusion, the Board notes in particular the relatively short duration of the drilling and completion activities, and the commitments made by Chesapeake to reduce noise levels. The Board accepts, however, that there remains a degree of uncertainty respecting the impacts that may occur.

In this respect the Board believes that every precaution should be taken to reduce the potential impacts to a minimum. The Board sees merit in Chesapeake's commitment to having a qualified veterinarian monitor the alpacas before, during, and after the drilling operation. It believes that Board staff should be involved with Chesapeake in the selection of the rig and noise attenuation equipment and that frequent Board inspection of drilling operations would be appropriate. The Board believes that the involvement of its staff in the selection of the drilling rig and noise attenuation equipment is sufficient to protect the interests of the Ranch. It should not be necessary for the Ranch to be directly included in this process. The Board further sees merit in restricting drilling to the summer months when the rig noise would be more effectively screened by foliage cover. If possible the

rig should also be oriented in a manner such that noise would be directed away from the Ranch and the Sabo property as much as possible.

The Board also proposes that Chesapeake conduct a 24-hour ambient sound survey at the Oranchuk residence to obtain a representative sample of the existing ambient sound level in the area. This survey will be used to compare ambient noise levels with those recorded by Chesapeake at the Oranchuk residence during drilling. Although not on Ranch property, it is expected that the results will be representative of incremental noise levels experienced by the alpacas. The data will be collected as early as practical within the drilling period and the results of both surveys will be made available to the ERCB, the Sabos, and the Ranch. If the incremental increase in sound appears to be having a negative impact on the animals, then further rig noise attenuation will likely be required.

7 CONCLUSION

On the basis of the evidence presented at the hearing, the Board accepts the need for the proposed CHESAPEAKE ET AL WHMUD 16-12-51-25 well to obtain oil and gas production from the Ellerslie Formation. Furthermore, the Board believes that the well, provided particular care is taken to ameliorate noise and other sources of disturbance, can be developed with only minor impacts on nearby residences and commercial/agricultural operations, and that Chesapeake will make all reasonable efforts to minimize these impacts. The Board expects that Chesapeake will implement those undertakings made in its application and during the hearing to reduce the potential adverse impacts on the local residents.

Notwithstanding its belief that the proposed well can be drilled with acceptable impacts on the area, the Board is also of the opinion that, given the proximity of the well to area residents, Chesapeake must be fastidious and thorough in carrying out every detail of its proposed operations so as to minimize impacts. Should unacceptable impacts occur, it would be necessary to suspend drilling operations immediately until corrections were made.

8 DECISION

The Board approves the application and a well licence will be issued in due course, subject to the commitments and undertakings made by Chesapeake in its application and at the hearing, as well as to the following conditions imposed by the Board:

- Chesapeake shall consult with the ERCB in the selection of its rig and noise attenuation equipment.
- An ambient noise survey shall be conducted by Chesapeake at the Oranchuk residence before the drilling of the well, the results compared to survey results obtained by Chesapeake during the drilling of the well, and provided as soon as possible during the drilling/completion operations to the Ranch, the Sabos, and the ERCB.
- Drilling operations shall be carried out during the summer months, and every reasonable effort shall be made to confine noisy drilling operations (eg. tripping) to the daylight hours.
- Operations that allow greater flexibility, such as off-loading pipe, will be restricted to daylight hours.
- The Sabos, the Oranchuks, the Ranch, and the Edmonton Area Office of the ERCB shall be notified prior to drilling into the Ellerslie Formation.
- The ERCB shall be notified prior to clearing for road construction and prior to drilling.

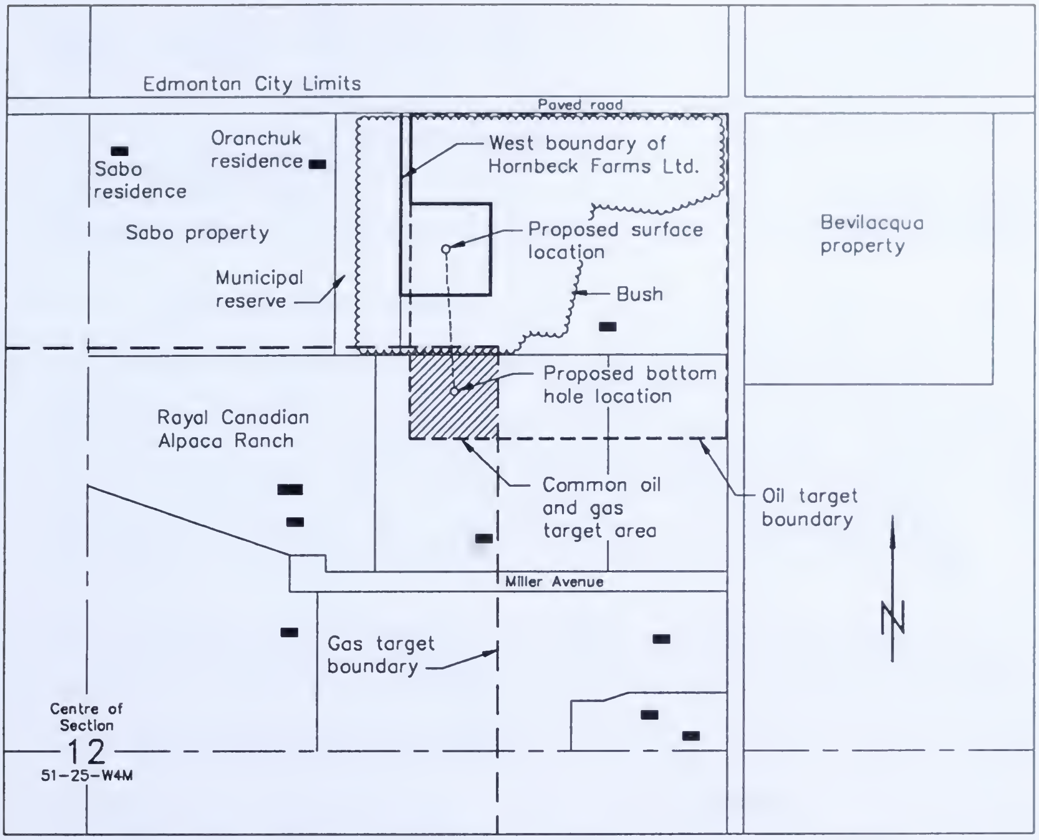
DATED at Calgary, Alberta, on 4 June 1990.

ENERGY RESOURCES CONSERVATION BOARD

J. P. Prince, Ph.D., Board Member

B. F. Bietz, Ph.D., Board Member

J. D. Dilay, P.Eng., Acting Board Member



PROPOSED WELL LOCATION
CHESAPEAKE ET AL WHMUD 16-12-51-25-W4M
Application No. 891846

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

POWER RESOURCE DEVELOPMENT CORPORATION
18-MW WOOD-WASTE-FIRED
ELECTRIC POWER PLANT
WHITECOURT AREA

Decision D 90-4
Application 891671

1 APPLICATION AND HEARING

Power Resource Development Corporation (PRDC) applied, pursuant to sections 9, 12, and 17 of the Hydro and Electric Energy Act, for approval to construct and operate an 18-megawatt (MW) wood-waste-fired electric power plant northwest of the town of Whitecourt. The plant would be located on Crown land in section 4, township 60, range 12, west of the 5th Meridian. The plant location relative to the town of Whitecourt is shown on the attached area map. The plant would be connected to the electric system of TransAlta Utilities Corporation (TransAlta).

The application was considered at a public hearing in Whitecourt on 24 April 1990, with Board Member J. P. Prince, Ph.D., and Acting Board Members E. G. Fox, P.Eng. and K. G. Sharp, P.Eng., sitting (the Board).

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Power Resource Development Corporation (PRDC) D. Lobay	R. Hepple, P.Eng. D. Vinson, P.Eng.
Whitecourt Chamber of Commerce (the Chamber of Commerce) S. Wilcox	
Town of Whitecourt (the Town) H. Kreiner	
Millar Western Industries Ltd. (Millar Western) R. Clark, P.Eng.	
Whitecourt Environment Society (the Environment Society) B. Whittaker	

THOSE WHO APPEARED AT THE HEARING (continued)

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Friends of the Athabasca (FOTA) R. Eberhardt	
Alberta Environment B. MacDonald, P.Eng. R. Dobko, P.Eng.	
Energy Resources Conservation Board (ERCB) staff T. F. Homeniuk, P.Eng. R. L. Schroeder	

1.1 Background

The proposed project has been granted preliminary allocation under the Alberta Government's Small Power Program. The program is administered by the Alberta Department of Energy pursuant to the Small Power Research and Development Act (the Act). Under the Act, an electric utility company, in this case TransAlta, is required to purchase, at a price set out in the Act, the energy generated by a plant having allocation under the program. Therefore, if PRDC's application is granted, the ERCB would issue an approval to allow the construction and operation of the plant and its connection to the electric system of TransAlta. A future application would be made for approval to construct approximately 700 metres (m) of 138-kV transmission line to connect the plant to TransAlta's substation located across Highway 43 from the plant site.

2 PLANT DESCRIPTION

The proposed plant would consist of a steam-turbine generator set, a boiler, fuel storage pile, fuel handling system, ash handling system, cooling water system and pumphouse, and various other related auxiliary facilities. The fuel would consist of wood waste from the sawmill of Millar Western. Some 39 tonnes per hour (308 000 tonnes per year) of fuel would be required, based on a 90 per cent capacity factor for the plant. Fuel would be hauled utilizing self-unloading trailers coupled to conventional tractors. It is anticipated that two 25-tonne truckloads per hour would be hauled, 24 hours per day, 5 days per week. Discussions are under way with Alberta Transportation regarding the establishment of a turning lane for the fuel trucks. Natural gas would be used for start-up and low-load flame stabilization and it would comprise about 5 per cent of the total fuel.

In its original application, PRDC proposed that the fuel would consist of wood waste and pulp mill sludge. In response to concerns expressed regarding the burning of pulp mill sludge, PRDC, prior to the hearing, amended its application to exclude pulp mill sludge from the fuel in the initial operation of the power plant. Once the plant is operational, PRDC would apply for approval to conduct tests to determine if there are any environmental hazards associated with the combustion of pulp mill sludge. If no hazards or concerns are identified, PRDC would propose to include pulp mill sludge as a fuel in its plant.

Cooling water for the plant would come from the Athabasca River. The applicant has entered into an agreement with Esso Resources Canada Limited to acquire an existing pumphouse and intakes located across Highway 43 from the proposed plant site. Some additional pipelines would be required between the pumphouse and the proposed plant. Discussions are under way with Alberta Transportation regarding crossing the highway with the pipelines. Approximately 27 cubic metres per minute (7000 gallons per minute) of cooling water would be circulated through the plant, then discharged into a spray cooling pond. The cooling water would be monitored for water quality and, if necessary, treated before being returned to the river at a temperature less than 30 degrees Celsius (^{o}C).

PRDC proposes to construct a wood-pile runoff collection system to ensure that runoff from the fuel pile is collected in a retention basin. Water from the retention basin would be monitored and, if necessary, treated before being routed to the spray cooling pond and discharged to the river.

Ash would be transported by enclosed tractor trailer to the Whitecourt municipal landfill site.

3 ISSUES

When the Board considers an application for a proposed power plant that has been granted preliminary allocation under the Small Power Program, the question of whether the energy that would be generated by the plant is needed is not an issue. As indicated in Section 1.1 of this report, the Act requires that the electric utility company purchase that energy.

The Board believes the following to be the remaining major issues arising out of the PRDC application:

- o the suitability of the plant site
- o environmental issues
  - air quality
  - water quality
- o economic and social impacts

4 SUITABILITY OF THE PLANT SITE

PRDC proposes to construct its plant on a 30-hectare site owned by the Crown. The Public Lands Division of Forestry, Lands and Wildlife has indicated that the site would be made available to PRDC upon ERCB approval of the application. Friends of the Athabasca (FOTA), expressing some concern with respect to the location of the proposed plant site, questioned why PRDC had not considered other viable sites for the plant. It argued that the proposed plant is nearer to residents of the town of Whitecourt than the 5 kilometres (km) indicated by PRDC. PRDC indicated that other sites were investigated; however, the proposed site was chosen because of its close proximity to a major highway and a fuel source, the availability of cooling water, and access to an existing water intake structure on the Athabasca River and a major electrical substation some 700 m from the plant site.

The northern portion of the site, upon which PRDC proposes to build the plant, is above the 100-year flood plain. The southern portion of the site, which is within the flood plain, would be used temporarily for storage of equipment and material while plant construction takes place.

Responding to FOTA's concerns regarding the possibility of surface drainage from the plant site migrating through the soil and reaching the Athabasca River, PRDC stated that all surface drainage would be collected and monitored prior to release. If its project is approved, PRDC would clear the site and undertake hydrology and soils studies to determine the percolation rates of the soils. Appropriate measures would then be designed into the retention and cooling ponds to ensure drainage did not occur to the subsoils.

Addressing the concern expressed by FOTA regarding potential fogging near the proposed site, PRDC submitted a report from a consultant that it had asked to review this matter. PRDC stated that, based on the consultant's advice, fogging from its spray cooling pond would likely be a problem only if the cooling water temperature reached 65°C. Actual cooling water temperature is expected to be in the +32°C range and, therefore, fogging is not expected to be a problem.

PRDC, in response to a question from the Whitecourt Environment Society (the Environment Society) with respect to abandonment of the project, indicated that, as a condition of its Land Lease Agreement, it would be responsible for removing all structures from the project site. As well, it would be required to reclaim the site in an acceptable manner. PRDC indicated that, as further insurance in the event it abandoned the project without reclaiming the site, income from the sale of plant facilities could be used to pay for reclaiming the site.

The Board has reviewed the reasons provided by PRDC for selecting the proposed site. It agrees that ease of access to the project site and proximity to a cooling water source, a fuel source, and electrical facilities are important criteria that must be satisfied to make a project viable. The proposed site satisfies these criteria. In addition, it is located near the town of Whitecourt so that advantage can be taken of the various infrastructures and services provided in the town.

The Board has also considered the concerns expressed by FOTA and the Environment Society. It notes that no permanent facilities would be located in the 100-year flood plain, that fogging is not expected to be a problem at the proposed cooling water temperatures, and that the retention and cooling ponds will be designed on the basis of the results of the soils percolation tests that would be undertaken. It further notes that the applicant is in the process of reaching agreement with Alberta Transportation to have a turning lane provided from Highway 43 to the proposed site. With respect to site reclamation when operation of the plant is discontinued, the Board notes that restoration of the site is covered under the Land Lease Agreement with the Department of Forestry, Lands and Wildlife.

The Board is satisfied that, from the point of view of matters relating directly to the physical site, the site is acceptable. The concerns relating to proximity of the site to the town and also concerns relating to water quality, plant emissions, and local temperature inversions are addressed in the next section of the report.

5 ENVIRONMENTAL ISSUES

PRDC stated that the proposed plant would be designed, constructed, and operated to meet the various environmental standards and requirements under the Clean Air, Clean Water, and Water Resources Acts. It stated that any conditions of its Land Lease Agreement from Alberta Forestry, Lands and Wildlife would also be met.

5.1 Air Quality

PRDC stated that emissions of carbon dioxide, carbon monoxide, and nitrogen oxides to the atmosphere would all be well below the limits allowed by Alberta's clean air standards. Only traces of sulphur dioxide would be emitted because the wood-waste fuel is essentially free of sulphur. Responding to concerns regarding ground-level concentrations of pollutants, PRDC stated that its studies show that, at a distance of 5 km from the plant, levels of nitrogen oxides would be 14 per cent of levels permitted by Alberta Environment guidelines. At lesser distances, the predicted ground-level concentrations were also found to be less than those permitted by Alberta Environment guidelines.

It further stated that studies done by Alberta Environment indicate that combining emissions from the proposed plant with emissions from the existing Millar Western and Alberta Newsprint plants, even under worst ambient conditions, including temperature inversion, would result in ground-level concentrations of one-third the permissible levels.

In summary the proposed plant, using controlled combustion, would result in a significant reduction in the current level of pollutants and would also produce energy from what would otherwise be a waste product.

PRDC stated that a filter bag house would be used to remove ash particles from its combustion gas prior to releasing the gases to atmosphere through a 125-foot-high stack. Prior to entering the bag house, the gases would be used to dry the fuel. This would ensure that any embers contained in the gases would be quenched and the temperature of the gases would be within acceptable limits when entering the bag house.

In their submissions, the Environment Society and FOTA both expressed concern about emissions from the combustion of pulp mill sludge, because of chemicals contained in the sludge. PRDC stated that, in its view, pulp mill sludge can be safely combusted. However, in response to the concerns, it amended its application to exclude sludge from the fuel. It indicated that, after the plant is operating using only wood waste as the fuel, it would apply to the ERCB and Alberta Environment for approval to conduct tests to demonstrate that pulp mill sludge can be combusted in an environmentally safe and acceptable manner. In response to questions from ERCB staff, it stated that it is prepared to conduct an information program to inform the public of its intentions to test the combustion of pulp mill sludge. The information would include an analysis of the sludge, a description of the tests to be conducted, the emission standards to be met, and the results of the tests. If the tests were successful, PRDC would submit an application to amend its approval to add the pulp mill sludge as a fuel source. The Environment Society and FOTA both indicated that they would wish the matter of adding pulp mill sludge as a fuel source to be considered by the Board and information made available to the public.

The Town expressed the view that PRDC's proposal meets or exceeds the necessary environmental standards and that the impact on the area would be minor.

The Chamber of Commerce submitted that the proposed plant, utilizing latest and proven technologies, provides answers to Whitecourt's fly ash and wood-waste problems.

Millar Western, describing the various problems it has faced in dealing with its wood waste, submitted that the proposed plant offers an environmentally sound solution to disposing of these wastes.

The Board has considered the way in which the applicant proposes to meet the applicable air emission standards and the expected results. It is satisfied from the evidence submitted that the proposed plant can be constructed and operated to meet those standards. The Board also believes that, compared to the current method of disposing of the wood waste using tepee burners, the proposal before it is a far superior means of controlling particulates and emissions of nitrogen oxides.

Although the subject application excludes sludge from the fuel, the Board notes PRDC's intention to test the sludge at some future date and, if successful, apply to add it as a fuel source. Assuming that the current application is granted and an approval to construct the proposed plant is issued, PRDC would be required to apply to have the approval amended if it wished to change or add another fuel. Should that happen, the Board would expect PRDC to conduct the kind of public disclosure and information program it committed to at the hearing. Whether or not a further public hearing would be held would be determined on the basis of what is specifically proposed, concerns that are identified at that time, and whether or not there are any valid objections.

5.2 Water Quality

PRDC stated that separate systems would be installed to collect, monitor, and, if necessary, treat surface runoff, drainage, and cooling water prior to the water being discharged to either the surrounding area or to the river.

The plant cooling water, which would be obtained from the Athabasca River, would not have anything added to it except for minor amounts of chlorine to control algae growth in the main condenser. Cooling water from the condenser would be directed to the spray cooling pond for temperature control and monitoring of chlorine content before being returned to the river.

Run-off from the fuel pile would be directed to a retention pond where it would be monitored for biological content such as lignans and tannins, treated, if necessary, then directed to the spray cooling pond and discharged to the river.

Site drainage would be directed to a retention pond to allow silt to settle out before discharging to the area adjacent to the plant site.

Responding to concerns from FOTA that lignans and tannins could find their way to the river, PRDC presented information that indicated that leachate from the wood-waste fuel could be treated using bacteria to break down these compounds, if necessary, prior to discharging to the river. Commenting on concerns regarding the biological oxygen demand (BOD) of the river, PRDC stated that its plant is not being proposed as

a means of addressing any oxygen deficiency problem that may exist in the river. However, operation of the spray system in its cooling pond would tend to increase the oxygen content of the water being returned to the river, thereby having a positive impact on any BOD problem that might exist.

The Board is satisfied that PRDC's proposed methods of collecting, monitoring, and treating the various streams of water prior to discharging are acceptable. The Board accepts that concerns expressed by the Environment Society and FOTA are valid, but believes that they are appropriately addressed by PRDC.

6 ECONOMIC AND SOCIAL MATTERS

PRDC indicated that the project would provide twenty full-time jobs, fifteen of which should be able to be filled locally. Construction of the plant would last for a period of 16 to 19 months, employing about eighty people during this period. Many of the construction personnel should be available locally. Approximately $25 million would be spent on equipment and supplies for the project. PRDC also submitted that the infrastructure needed to support development of its proposed plant already exists in the town of Whitecourt.

The Chamber of Commerce supported the application. It submitted that the project would have a positive economic, social, and environmental impact on the area. This would include positive effects on the taxation base of the local municipal government and school boards, significant benefits to the Whitecourt economy, and the elimination of wood waste from Millar Western, as well as an environmentally safe form of producing electricity.

Millar Western also supported the application. It submitted that the proposed plant would allow it to dispose of its wood waste in an environmentally safe and cost-effective manner.

The Board agrees that the proposed power plant, besides having an initial positive effect on the local economy, would also have long-term benefits. It also accepts that much of the infrastructure needed to support the development of the plant is already in place.

7 CONCLUSION

The Board notes that, although legitimate concerns regarding the proposal were expressed, none of the interveners opposed the project's overall concept.

Based on evidence presented in the submissions and at the hearing and taking into consideration the environmental concerns, economic and social impacts, and the suitability of the proposed power plant site, and recognizing that PRDC has received preliminary allocation for the proposed electric generating capacity under the government's Small Power Program, the Board concludes the proposed plant is acceptable.

If, in the future, PRDC decides to utilize pulp mill sludge as a fuel source in its power plant, an application to amend its approval would be required. The Board would expect PRDC to follow through with its commitment, as discussed at the hearing, to provide information related to burning pulp mill sludge.

8 DECISION

The Board grants the application of Power Resource Development Corporation to construct and operate an 18-MW wood-waste-fired electric power plant near Whitecourt and to connect the plant with the electric system of TransAlta. The location and details of the plant would be as more particularly described in the application and shown on the attached figure. The necessary approvals are being issued concurrent with this decision.

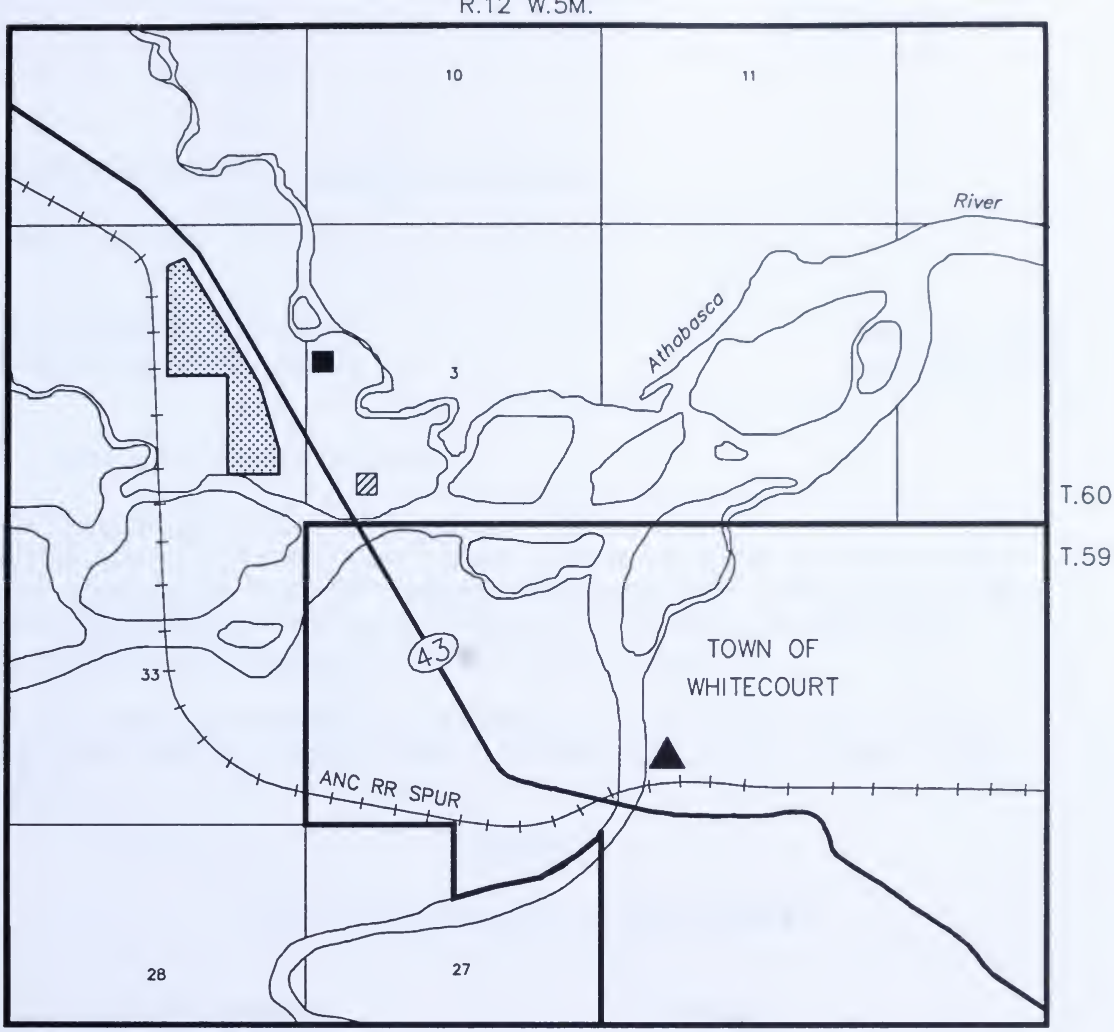
DATED at Calgary, Alberta, on 17 May 1990.

ENERGY RESOURCES CONSERVATION BOARD

J. P. Prince, Ph.D.
Board Member

E. G. Fox, P.Eng.
Acting Board Member

K. G. Sharp, P.Eng.
Acting Board Member



▲ Millar Western pulp mill

■ Existing TransAlta substation

▨ Existing Esso Resources pumphouse

Proposed power plant – Sec.4–60–12 W.5M.

PROPOSED PRDC ELECTRIC POWER PLANT
Application No. 891671
Whitecourt Area

D90–4

ERCB

R243

ENERGY RESOURCES CONSERVATION BOARD

Calgary Alberta

CITY OF MEDICINE HAT
POWER PLANT EXPANSION

Decision D 90-5
Application 891967

1 APPLICATION AND HEARING

The City of Medicine Hat (the City) applied, pursuant to sections 9 and 17 of the Hydro and Electric Energy Act, for approvals to construct, connect, and operate an expansion to the City's existing power plant. The expansion would consist of two 17-MW gas turbine driven generators and associated heat recovery boilers and one 30-MW steam turbine driven generator. It would be connected to the City's electric system.

The application was considered at a public hearing on 17 and 18 April 1990, in Medicine Hat, Alberta, with N. A. Strom, P.Eng., J. P. Prince, Ph.D., and R. G. Evans, P.Eng., sitting.

TABLE 1

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations Used in Report)	Witnesses
The City of Medicine Hat (the City) P. Smith, Q.C.	J. W. Kerr, P.Eng. R. M. Nicolay, P.ADM. R. G. Kovar, P.Eng. P. G. Sagert, P.Eng. H. J. Kolross
TransAlta Utilities Corporation (TransAlta) T. Dalgleish	G. M. Steeves, P.Eng. N. J. Brausen, P.Eng.
Alberta Power Limited (Alberta Power) W. S. McKall	J. R. Frey, P.Eng. B. Laing, P.Eng. K. Scott, P.Eng.

THOSE WHO APPEARED AT THE HEARING (cont.)

Principals and Representatives (Abbreviations Used in Report)	Witnesses
The City of Edmonton/Edmonton Power (Edmonton) G. A. Salembier	
The City of Calgary (Calgary) D. D. Short	
The Cities of Red Deer and Lethbridge (Red Deer and Lethbridge) J. A. Bryan, Q.C.	R. L. Bruggeman, P.Eng.
Industrial Power Consumers Association of Alberta (IPCAA) A. G. MacWilliam	
Medicine Hat and District Chamber of Commerce (the Chamber of Commerce) R. Smythe	R. Smythe
Medicine Hat and District Labour Council (the Labour Council) H. Mueller	H. Mueller
Medicine Hat Industrial Group (the Industrial Group) R. Holowachuk	R. Holowachuk
Municipal District of Cypress No. 1 (the M.D. of Cypress) L. Perschon	L. Perschon
Town of Redcliff (Redcliff) R. Giesbrecht	R. Giesbrecht
Energy Resources Conservation Board staff (Board staff) M. L. Asgar-Deen, P.Eng. S. S. Lota, P.Eng. J. F. Wilson, P.Eng.	

2 GLOSSARY

In the context of this proceeding, a few terms were used for which a range of meanings might be inferred. To avoid misunderstanding, a list of these terms and their meanings as understood by the Board and as used in the report are included in the appendix to this report.

3 BACKGROUND TO THE APPLICATION

3.1 Plant Description

The City owns and operates the power plant and electric distribution system which supply all of its electricity requirements. The power plant consists of two gas turbine generators, each having a capacity of 34 MW (nominal)[1] and operating in combined cycle with four steam turbine generators having a total capacity of 53 MW. The gas turbine exhaust gas is utilized in heat recovery steam generators to produce steam for the steam turbines. Conventional gas-fired boilers provide back-up steam generating capability.

The City also owns and operates a simple cycle gas turbine generator rated at 17 MW, located in the industrial area north of the main power plant. This unit is remotely controlled and is used mainly for peaking and reserve requirements.

The total installed capacity in the City's system is about 138 MW.

In 1989, the City generated some 563.3 GW.h of electric energy, or about 1.4 per cent of the total provincial generation, and experienced a peak load of about 108 MW. The City's electric distribution system is connected with the Alberta interconnected system (AIS) via three 138-kV transmission lines and a transformer with a rating of 47.5 MVA.

The City evaluated various alternatives available to meet its capacity and energy requirements for a 15-year period, beginning in 1988. Several alternatives to supply the City's future requirements were examined, including buying base-load power from TransAlta, purchase of unit power from Genesee or Sheerness with energy wheeled into the City, non-traditional sources of power such as solar, wind, fuel cells, local industrial waste heat, and continued self-generation by expanding the City's existing power plant.

The City concluded that the best alternative, on the basis of least cost, minimal effects on the environment, and greatest efficiency, is to expand its existing power plant.

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[1] Rating of gas turbines at standard atmospheric conditions. All gas turbine ratings shown in this report are nominal.

To meet its requirements up to 2003, and based on the current forecasts of load, the City decided to add generating capacity in two phases. In Phase I, two 17-MW gas turbine generators would be installed by 1992. Each gas turbine generator would be equipped with a heat recovery steam generator. In Phase II, a 30-MW condensing steam turbine generator would be installed by 1996. The proposed addition would form a fully integrated combined cycle operation with the existing power plant.

3.2 Royalty Treatment of Medicine Hat Gas

The City owns most of the gas that it uses to meet its electric, industrial, and residential requirements. The City also enters into third-party agreements for the purchase of natural gas.

All of the city-owned gas that the City uses is subject to special reduced Crown-royalty, provided the gas is not disposed of or sold for consumption or use outside the city, as prescribed in the City of Medicine Hat Gas Agreement between it and the Crown.

3.3 Previous ERCB Decisions

In 1975, the City applied for approval to install and operate a 17-MW gas turbine to meet its requirement for reserve and peaking capacity. The City stated that its needs would be supplied more economically by the proposed unit than from the interconnected system.

The City stated that the proposed unit would have significant short-term and long-term benefits to the City. As well, the existing transmission lines were not capable of supplying the City's combined requirement for firm and standby reserve capacity in 1976 and 1977.

TransAlta opposed the application on the basis that the proposed unit was not suitable in terms of long-range electric energy supply planning for southeastern Alberta. It stated that there was adequate reserve capacity within the AIS. Accordingly, TransAlta submitted a proposal to supply the City's additional firm and reserve capacity until suitable long-range plans could be made for supplying the Medicine Hat and area electric requirements.

The Board considered the application not only as it related to the City, but also having regard for its possible impact on the AIS. The Board approved the application and decided that the whole matter of supply of electric energy in the southeastern portion of the province should be considered at a separate proceeding.

Later in 1975, a Board-initiated proceeding was held to consider the matter of development and operation of facilities for the generation and supply of electric energy in the southeast area of Alberta for the 15-year period from 1975 to 1990. The Board concluded that electric demand in southeast Alberta would increase sufficiently in the future to warrant major

expansion of generation and transmission facilities in the area. Furthermore, the Board concluded that the expansion of the 240-kV system into southeast Alberta would be important to efficiently supply future load in the area.

The Board observed that the more important factors in supplying the City's future electric requirements included relative economics and the financial impact that various alternatives would have on the City's customers.

The Board concluded that, in view of the anticipated rise in the price of natural gas, the City should increase its use of existing and future interconnections with the AIS, thereby reducing and eventually eliminating the use of its base-load gas-fired generating units. The Board suggested that the optimum alternative for the City would probably involve construction of a 138-kV line from the AIS, additional peaking capacity in the late 1970s, then additional transmission capacity to allow the City to increase its use of energy from the AIS.

In conclusion, the Board noted that economic and orderly development of transmission and generation capacity in the southeast area of Alberta would require effective co-operation among the utility operators. Also, it suggested that a positive effort would be required to reach equitable solutions so that undue costs would not occur to consumers anywhere on the Alberta electric system.

In 1978, the City applied for approval to construct two 30-MW gas turbine generators and associated heat recovery steam generators, for installation by 1980, to be operated in combined cycle with existing steam turbine generators. The City referred to this as repowering. The application was based on the City's forecast requirement for additional firm and reserve capacity by 1980. In the interim, the City had contracted for short-term purchase of reserve capacity from TransAlta. The City stated, as it had in 1975, that the then existing 138-kV transmission lines from the AIS would not be capable of supplying both the firm and reserve requirements of the City beyond about 1980.

TransAlta did not oppose the application but stated its concern about the need for the City to provide spinning reserve of up to 45 MW in the event that its largest unit experienced a forced outage. TransAlta stated that, under those conditions, either instantaneous load shedding or pick up of the load by the AIS would be required. Should the latter occur, appropriate arrangements should exist to cover the service provided by the AIS. TransAlta further stated that the City must resolve the approach it intended to take in supplying its reserve needs, as well as its firm power requirements, beyond 1980.

The Board, in its analysis, concluded that, because the gas which the City uses to generate electric energy is subject to special royalty arrangements, the cost of repowering would be less than the cost of purchasing electric energy requirements from the AIS. The Board approved the application, noting that the City's proposal involved more efficient use of gas such that additional quantities beyond those already allocated for electric energy

generation may not be necessary. If the Board had denied the application, there was a possibility that the existing, and less efficient, plant would have had to be continued to be operated because additional transmission capacity would not have been built in time.

The inclusion of the above discussion as background to the decision report is intended only to provide the reader with an historical perspective on the City's previous applications. The circumstances in 1990 are somewhat different than those existing at the time of previous applications. In particular, the AIS currently has significant surplus capacity that could be used by the City to meet its reserve capacity needs.

3.4 Electric Energy Marketing Agency

The Electric Energy Marketing Agency (EEMA) was established in 1982 with the mandate to reduce cost-of-service differentials across the province. This objective is achieved by EEMA purchasing all of the electric energy produced by TransAlta, Alberta Power, and Edmonton at an interface between their respective transmission and distribution systems, pooling these costs, then selling the energy back to the three utilities at a pooled price. Reimbursement to Calgary, Lethbridge, and Red Deer, for transmission lines they own, is also part of the pooling process. The purchase, pooling, and re-sale of electric energy is done on the basis of three consumer groups: residential/farm, large industrial, and general service. The price, in respect of each consumer group, at which electric energy is sold to EEMA by each of the three utilities, is established by the Public Utilities Board (PUB).

Pooling results in the transfer of payments among the participating utility companies and compensation to cities which own transmission facilities.

The City, through its membership on the EEMA implementation committee, participated in discussions leading up to the formation of the agency. However, when EEMA was finally established, the City declined participation in the pooling process.

3.5 Public Utilities Board

The PUB sets prices at the EEMA pooling interfaces for the three generating utilities, TransAlta, Alberta Power, and Edmonton. The PUB also sets rates that the investor-owned utilities charge their different classes of customers. In addition, upon application under section 73 of the Public Utilities Board Act, the PUB could be requested to review rates established by agreement between utility companies or between a public utility and a municipality.

3.6 Hydro and Electric Energy Act

Under the provisions of section 9 of the Hydro and Electric Energy Act (the Act), approval of the Board is required to construct and operate a power plant. Pursuant to section 17 of the Act, approval is required to connect the plant to an existing electric system.

Section 17 of the Act also empowers the Board to set terms and conditions for connecting a power plant to an existing electric system and, in the event that the parties connecting their facilities cannot agree on the amount of the compensation, the Board may set the basis for compensation.

Industrial cogenerator plants, that supply some or all of their electric energy requirements (such as Dow Chemical, Syncrude, and Suncor) and that have the capability to feed electric energy back into the Alberta electric system, are also subject to the provisions of sections 9 and 17 of the Act. Those that supply some or all of their own electric power requirements but do not have the capability to feed electric energy back into the Alberta electric system (such as the pulp mill at Hinton and the Foothills Hospital in Calgary), are exempted under section 11 of the Act.

For planning purposes, on-site industrial generating plant capacity is regarded as a reduction in the amount of customer load to be supplied from the AIS.

3.7 Review of Electric Generation Planning Parameters

In June 1989, TransAlta, Alberta Power, and Edmonton requested the Board to review certain matters relating to generation capacity expansion planning for the AIS. These matters were presented in three reports which dealt with assessment of peak continuous ratings of the AIS generating units, amount of reliance that should be placed on external interconnections, and adoption of an interim reliability criterion pending the outcome of a full-scale review of the existing criterion.

At a public meeting held to consider the request, the City expressed the view that, for purposes of the review, it is not part of the AIS. Its view was based on the fact that the City is not a member of the power pool and that the AIS is an entity which is defined by its day-to-day and yearly operation, including load dispatch on a one-system basis.

In March 1990, the Board issued Report D 90-1 wherein it discussed its findings and conclusions regarding peak continuous ratings of the AIS generating units, reliance on external ties, and interim reliability criterion to be used for generation expansion planning.

These parameters will be reviewed again in the near future but, until then, the findings in Report D 90-1 should be used to assess whether or not any surplus or deficit capacity exists within the AIS.

4 DEFINITION OF THE ISSUES

The Board notes that none of the participants at the hearing had any fundamental opposition to the City's proposal. However, several participants expressed concern regarding the timing of the proposal. Therefore, the Board concludes that in order to properly address this issue, the following matters must be considered:

- technical and environmental merits of the proposed expansion;
- meaning and importance of one-system planning;
- need for the plant and its timing; and
- economics of the various options.

This report will discuss the topics listed above as they relate to the timing of the applied-for facilities.

5 TECHNICAL AND ENVIRONMENTAL MERITS OF THE PROPOSED EXPANSION

5.1 Views of the Participants

The City proposed to install generating capacity in two phases. In Phase I, two refurbished 17-MW gas turbine generators and associated heat recovery boilers would be installed by 1992. In Phase II, a 30-MW condensing steam turbine generator would be installed by 1996. The 64-MW proposed expansion would satisfy the City's firm and reserve requirements until about the year 2003.

The City stated that the choice of two 17-MW gas turbine generators rather than one 34-MW gas turbine was based on the availability of suitable used gas turbines for refurbishment. Additionally, the smaller units are more suitable for cycling on/off duty when both units may not be required during low-load periods. The heat recovery boilers would be equipped with supplementary gas-firing capability, to provide additional steam supplies if and when required.

The proposed expansion would be located at the City's existing power plant. The existing switchyard would be expanded to accommodate the connection of proposed generators. A small amount of additional condenser cooling water would be drawn from the South Saskatchewan River when Phase II is installed.

The City stated that the proposed expansion would increase operating flexibility and efficiency of the whole plant. Furthermore, the proposed expansion would not only meet current regulations for plant emissions but would reduce overall emissions.

None of the participants questioned the technical merits of the proposed plant expansion. Some of the participants acknowledged that the proposed plant provides flexibility in meeting short lead times for installing additional capacity and would provide higher thermal conversion efficiency and achieve lower emissions. TransAlta stated that the type of combined cycle plant proposed by the City could prove to be an attractive future option for the AIS as well.

5.2 Views of the Board

The Board believes that the phased nature of the proposal lends itself to providing flexibility in planning future additions to the provincial system provided it can be integrated into a single provincial plan. The Board agrees with the City that the proposed plant expansion would increase operating efficiency and lower overall emissions from the City's plant. Therefore, the Board finds the proposed expansion to be technically and environmentally acceptable.

6 MEANING AND IMPORTANCE OF ONE-SYSTEM PLANNING

6.1 Background

Prior to the establishment of the Electric Utility Planning Council (EUPC) in the early 1970s, each utility planned and developed its electric facilities to ensure that the needs of its customers would be met. Accordingly, individual utility decisions to proceed with new projects were pursued with little consideration for the development plans of other utilities.

However, because of the economies of scale available with larger projects and associated reduction in costs, the concept of one-system planning, which combines utilities' needs and avoids duplication of facilities, came into being. One-system planning was intended to ensure co-ordinated development of new generation and transmission facilities, appropriately sized and located to efficiently serve all provincial consumer needs.

To facilitate a discussion, Figures 1 and 2 illustrate the relationships between the various members of the utility industry.

While the main players in one-system planning were intended to be utility companies serving utility customers, recognition of the plans and roles of industrial generating plants was also required for co-ordinated planning. Also, appropriate recognition of interconnections with adjoining provinces and power pools was required.

Since the early 1980s, several events have taken place that have had a significant impact on co-ordinated one-system planning within the EUPC and the role of each member utility in that process.

The first was the creation of the EEMA in 1982, which resulted in the regulated cost of electricity being equalized for various classes of electric utility customers. This equalization process had an impact on the three major generating utilities (TransAlta, Alberta Power, and Edmonton) as well as the major municipal distribution utilities (Calgary, Lethbridge, and Red Deer). Since the capital costs incurred in any one utility are rolled into the whole of the EEMA-determined cost base, the resulting AIS constituted a quasi one-system approach to electricity costs and ultimately rate schedules. As discussed below, the City was not included.

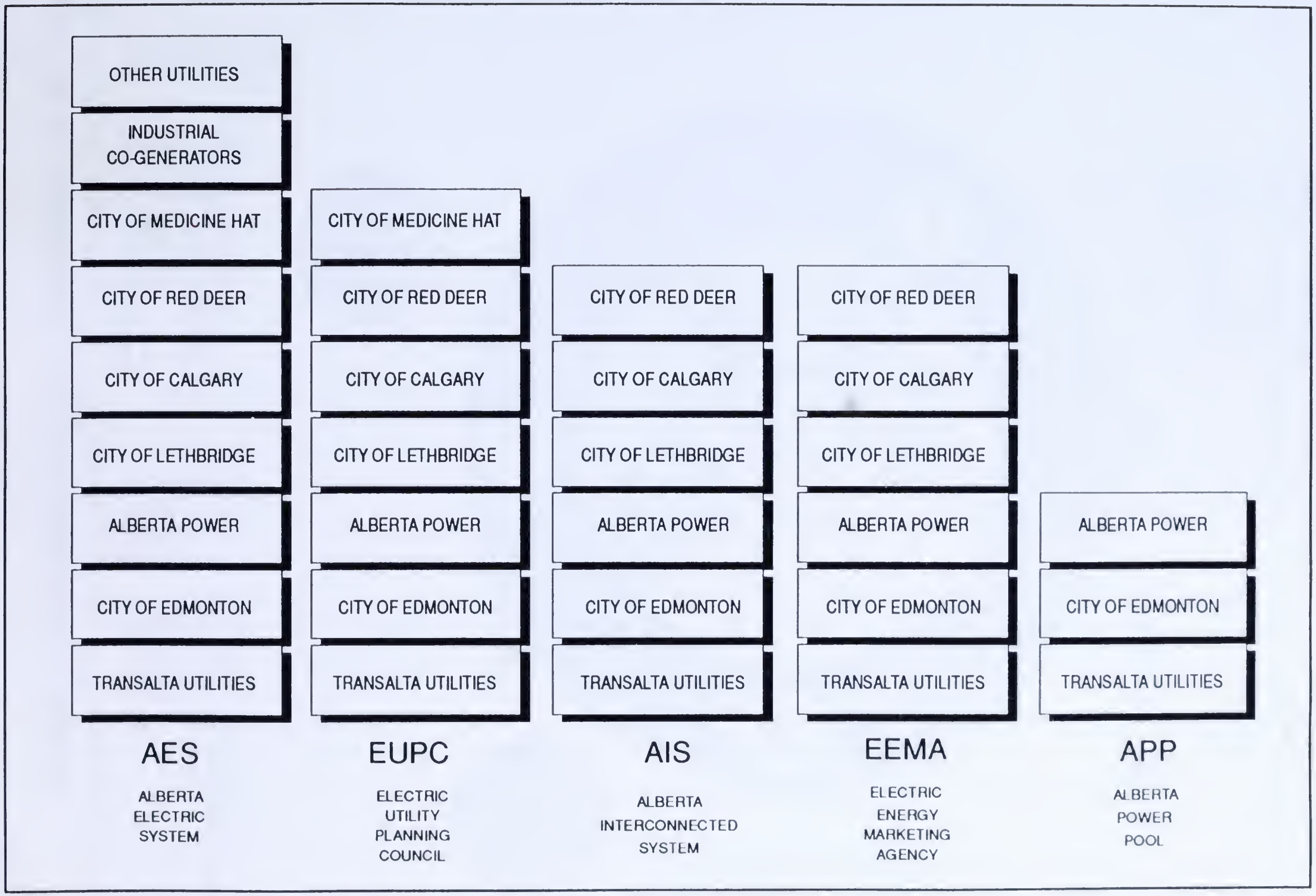
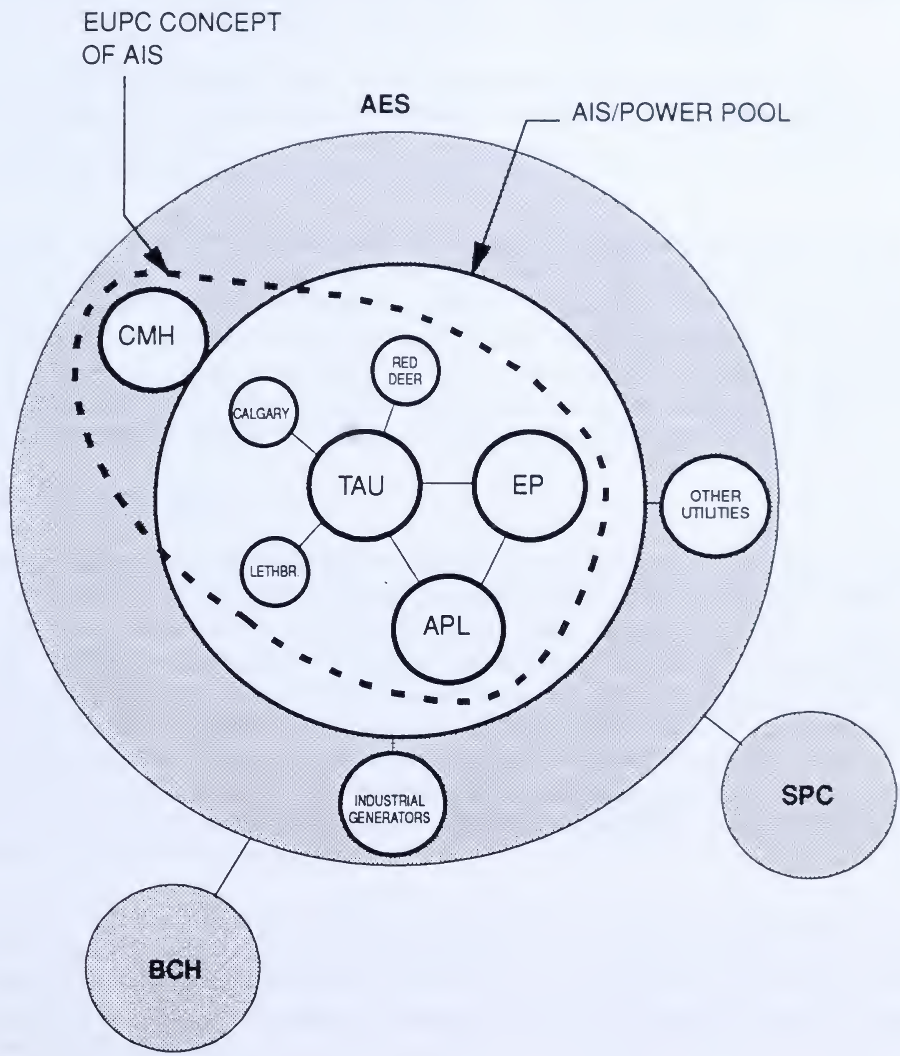


FIGURE 1 : ORGANIZATION OF ALBERTA UTILITIES



LEGEND

AES	- Alberta electric system	TAU	- TransAlta Utilities Corporation
BCH	- B.C. Hydro & Power Authority	EP	- City of Edmonton (Edmonton Power)
SPC	- Saskatchewan Power Corporation	APL	- Alberta Power Limited
CMH	- City of Medicine Hat	CALGARY	- City of Calgary
AIS	- Alberta interconnected system	LETHBR.	- City of Lethbrige
EUPC	- Electric Utility Planning Council	RED DEER	- City of Red Deer

FIGURE 2 : INTER-UTILITY RELATIONSHIPS IN ALBERTA

The second event was the creation of the Alberta Power Pool, comprising TransAlta, Alberta Power, and Edmonton, to co-ordinate the daily production of energy in order to minimize costs to consumers, thus complementing utility activities in the planning areas.

By choice, the City excluded itself from the cost-equalizing EEMA legislation. Thus, the City is not directly affected financially by the planning decisions of the other members of the EUPC. As well, by not taking up membership in the power pool, the City is not normally affected by the day-to-day operating decisions of the power pool.

TransAlta stated that the EUPC includes the City's load and generating-unit characteristics in its analysis of provincial electric needs as if the City were a member of the AIS. However, at the generation planning criteria meeting, that resulted in Decision D 90-1, the City stated that it is not part of the AIS and its facilities should not be incorporated in the AIS planning process. As a result of similar statements by the City and other parties at the hearing into the City's application, the EUPC's one-system planning process and the manner in which the City's load and generation should be included in that process becomes an issue.

6.2 Views of the Participants

The City stated that one-system planning, as defined by TransAlta and Alberta Power, uses a singular criteria, that being the need for additional generating capacity by the AIS. The City contended that one-system planning should also include other considerations such as type and size of units proposed, projected plant efficiency and emissions, reliability in the southeastern portion of the province, and the socio-economic impact in the area. In this context, the City stated that the proposed expansion would result in increased plant efficiency and reduced overall emissions, increased resource utilization, increased reliability of supply in the southeastern portion of the province, and increased socio-economic benefit in the area. The construction of additional capacity when surplus generating capacity exists on the AIS is the only detrimental aspect of the application.

TransAlta argued that the City is part of one-system planning for the AIS and its load was included in the analysis upon which the need for Sheerness Unit 2 and Genesee Unit 1 was based. Approval of the City's application would convey the message that the balance of the AIS and the EUPC ought not to continue to include the load and generating capacity of the City in planning AIS capacity.

TransAlta contended that, even if the City does not plan under the same rules as the rest of the utilities in the AIS, the planning rules which the City employs ought to be clearly articulated so that they may be properly taken into account for the purpose of one-system planning by the EUPC.

Alberta Power agreed with TransAlta, noting that the utilities have attempted to give effect to one-system planning in response to prompting by the Board.

Edmonton stated that the proposal should be consistent with the objectives of the Act and should reflect economic, orderly, and efficient development in the public interest. It further stated that, apart from need for generating capacity, relevant considerations should include diversity and reliability of supply, socio-economic factors, suitability of timing, and plant costs. As well, both short-term and long-term implications for all consumers in Alberta should be considered.

Calgary stated that it subscribed to one-system planning as described by TransAlta and Alberta Power. Furthermore, it held the view that one-system planning requires balancing of competing and conflicting interests of all the participants. Benefits can be realized only if the AIS is planned and developed as a single system and not as a loose conglomerate of a number of utilities. Calgary argued that the City is, in reality, part of the AIS and the AIS does not require additional generating capacity at this time.

Red Deer and Lethbridge stated that they subscribed to one-system planning, contending that all generation and transmission facilities should be planned and constructed having regard for province-wide requirements. They further argued that the Board should address whether allowing individual utilities, such as the City, to do their own planning, oblivious to integrated province-wide need, is really consistent with one-system planning.

6.3 Views of the Board

The Board notes that, in the past, the City has taken a different view of supply options than other members of the EUPC. This may have prevented effective co-ordination between the utilities. The City's view appears to arise from, among other things, the fact that it has an abundant supply of low-cost gas at its disposal. While gas turbines, in combined-cycle mode, can be more efficient than coal-fired units, their advantages relate primarily to their low unit cost and their comparatively short lead time to order and install. The City may also be influenced by a perception that capacity may be readily available from the AIS, if and when needed.

This combination of factors has, up until now, permitted the City to take a shorter-term approach to supply planning than is characteristic for province-wide one-system planning. However, the Board notes that the City's approach to supplying its own requirements has implications that are relevant to understanding how one-system planning has worked in the past. First, since about 1986, the City has been short of reserve capacity in its own system. Prior to entering into a short-term reserve purchase agreement in 1989, the City appears to have relied on its informal understanding with TransAlta for mutual assistance in the event of a major generation outage. The Board views this as a less than adequate means of ensuring supply.

Second, even though combined cycle gas turbine units are more efficient than coal-fired steam units, any choice between these options should recognize that gas may not always be available, let alone at current relatively low prices; whereas coal is abundant and low priced

and that situation is not likely to change for the foreseeable future. The appropriate planning time-frame to make prudent decisions in this respect should typically be longer than the City appears to have considered in the past.

Third, the Board views the different perceptions of the status of the City within the provincial electric system as a major barrier to resolving the City's role and participation within the co-ordinated one-system planning process. Some of the differences in views noted above may stem from interpretation of terminology used. For example, the City says that it is not part of the AIS, meaning it is not part of the Alberta interconnected system for planning purposes. However, the City is clearly a part of the provincial electric system since it uses and generates electric energy; is physically connected to the provincial electric grid, enjoys the advantages of the security available from it and is within the provincial boundaries, as illustrated in Figures 1 and 2.

Whether or not the City should be part of the AIS for planning purposes is a question at issue in this hearing. If the answer is no, then the province will not have co-ordinated one-system planning. It will have, at best, two-system planning. If the answer is yes, then the question becomes–how should the planning activities of the City and the other utilities and municipalities be integrated. Such integration could range from a loose association, with the City simply advising others of its plans for the future, to a close association, with the City belonging to both EEMA and the power pool.

The Board believes that even a loose integration would be better than having the two systems develop independently within the province. But given its committment to the concept of one-system planning, the Board would go further and say that it believes the City's load and generating facilities should be incorporated within the present EUPC planning process in a way that is eventually reflected in the actual development of the system. The Board notes the City's statement that no formal agreement exists with AIS members to share the City's reserves nor to dispatch the City's units when there is a need on the AIS, although mutual assistance has always been available on an informal basis when needed. The Board further notes that while there is a physical limitation imposed on such assistance, this could be corrected by upgrading the interconnection. Thus, the Board believes that effective one-system planning that incorporates the City into actual one-system development would not be difficult to achieve.

The Board notes that Medicine Hat City Council recently directed its electric utility to engage in long-term business planning. If the City can develop and communicate to the EUPC its long-term resource development plans, then those plans can be incorporated into a co-ordinated plan for the province. Meanwhile, the Board must decide whether independent development of the City's generating capacity is at least broadly consistent with the overall public interest.

7 NEED FOR THE PLANT AND ITS TIMING

7.1 Views of the Participants

The City forecasted that its peak demand would increase from 108 MW in 1988 to 157 MW by 2003. The corresponding energy requirements were forecasted to be 592.4 GW.h and 816.7 GW.h, respectively. The peak demand and energy, as forecasted by the City, are shown in Table 2. The City's reserve requirements are shown in Table 3.

TABLE 2

ANNUAL FORECAST OF ELECTRICAL PEAK DEMAND AND ENERGY REQUIREMENT

Year	Peak Demand (MW)	Energy (GW.h)
1988	108	592.4
1989	110	589.2
1990	114	605.3
1991	116	616.5
1992	118	627.6
1993	122	647.5
1994	124	657.9
1995	128	675.8
1996	131	692.3
1997	136	715.2
1998	138	726.8
1999	141	740.2
2000	146	752.5
2001	150	782.7
2002	154	801.7
2003	157	816.7

TABLE 3

ANNUAL RESERVE REQUIREMENTS

Year	Summer Rating of Local Generation (MW)	Forecast Peak Demand (MW)	Reserve Capacity (MW)	Reserve Capacity with Largest (33 MW) Unit Out of Service (MW)
1988	128	108	20	-13
1989	128	110	18	-15
1990	128	114	14	-19
1991	128	116	12	-21
1992	128	118	10	-23
1993	128	122	6	-27
1994	128	124	4	-29
1995	128	128	0	-33
1996	128	131	-3	-36
1997	128	136	-8	-41
1998	128	138	-10	-43
1999	128	141	-13	-46
2000	128	146	-18	-51
2001	128	150	-22	-55
2002	128	154	-26	-59
2003	128	157	-29	-62

The City stated that the most cost effective, efficient, and secure way to meet its future electric supply requirements is to increase local generation by expanding its power plant. Furthermore, the proposed additional generating capability would also benefit the surrounding area, which is supplied from the AIS, by stabilizing the system voltage and providing support during peak-load periods and during system disturbances.

The City noted that the existing transmission lines do not have the capability of supplying its present or projected needs and the proposed expansion would provide a source of locally produced power that does not depend on long transmission lines from the AIS.

The City stated that the proposed expansion is the least cost alternative to supply its future requirements. It would have real and measurable benefits to its customers and is, therefore, in the public interest. Furthermore, the proposed expansion is the only feasible alternative that would have a positive socio-economic impact on the area. It would help to ensure that the City's industrial base remains viable and secure and that all electric consumers in the City are provided with economic, reliable, and environmentally sound power. A number of local interveners endorsed these views.

The City acknowledged that surplus capacity exists on the AIS at the present time but stated that such surplus capacity is of a short-term nature. It is expected to disappear sometime between 1991 and 1993 whereas the City's application is based on its long term need for firm and reserve capacity.

The City expects to have the first of the proposed gas turbines operational in time to supply its reserve requirements in 1991. It contracted with TransAlta for reserve capacity during the peak periods of 1989 and 1990. However, it had not received an attractive enough offer from TransAlta to continue to supply it with reserve capacity so that the Phase I installation could be deferred to 1992 or 1993. The City stated that the impact of the proposed expansion on the costs payable by consumers of other utilities in Alberta would be negligible.

None of the interveners questioned the City's need for additional capacity to supply its projected requirements in the long term. The submissions of the other utilities generally related to the timing of the proposed expansion by the City in light of the current surplus capacity on the AIS, as shown in Table 4.

TABLE 4

AIS SURPLUS CAPACITY
UNDER THE 1989 EUPC PLANNING BOUNDS

Year	High Bound Forecast (MW)	Average of Low & High Forecast (MW)	Low Bound Forecast (MW)
1990/1991	582	582	582
1991/1992	442	543	631
1992/1993	171	414	663
1993/1994		253	570
1994/1995		75	485
1995/1996			374
1996/1997			267
1997/1998			181
1998/1999			90

NOTE: Reproduced from TransAlta's response to the information request by Red Deer and Lethbridge (Exhibit 8)

TransAlta stated that the City's application to install additional generating capacity to supply its reserve requirements in 1991 is premature in light of present surplus capacity on the AIS. It suggested that the City purchase reserve capacity from TransAlta and defer its expansion until such time as the provincial electric system requires additional generating capacity. TransAlta's offer of an 85/15 split of the benefits of the City's deferral of the proposed expansion was rejected by the City.

While Alberta Power acknowledged that the proposed expansion could be a suitable addition in the long term, it questioned the need to install the facilities by the date proposed by the City in light of the current surplus capacity on the AIS. It suggested that there are benefits to both City and AIS customers in deferring Phase I of the proposed expansion. It was of the opinion that agreement could be reached on an appropriate sharing of these benefits.

Alberta Power also expressed concern about the impact of the timing of the proposed Phase I expansion on the timing of the currently approved units on the AIS and the inclusion of costs of such units in the rate base.

Red Deer and Lethbridge submitted that there is no requirement for additional capacity on the AIS until the 1994 to 1996 period. Therefore, the City's application should not be approved. They also stated that, because of foregone revenues, approval of the application would indirectly incur higher rates which their customers, together with all other customers of the AIS, would have to pay.

7.2 Views of the Board

The Board observes that the City has a need for additional capacity and energy and notes that none of the participants at the hearing questioned the forecast presented by the City.

The Board notes that, in recent years, there have been a number of additions to the 240-kV and 138-kV transmission network serving the area that have enchanced the ability of the AIS to serve the City. The Board accepts the possibility that the proposed expansion could modestly increase the security of supply to the area in addition to that already offered by the existing plant and transmission system. However, it believes that supply from either the transmission system or the plant expansion would be sufficiently reliable to meet the City's needs.

The Board concurs with those participants who held the view that, in the longer term, the proposed expansion would be a suitable addition to the provincial electric system. The real question relates to the shorter term and whether the facilities should be approved for the applied-for in-service date or whether they should be delayed. The Board accepts TransAlta's evidence that currently there is excess capacity on the AIS and also notes that the City recognized that access to that capacity could be substituted for expansion of its own plant. In effect, the City's needs for the next 2 or 3 years could be supplied by the AIS, provided that a mutually agreeable and beneficial short-term arrangement could be made between TransAlta and the City. The Board believes that there is a way to share the benefits from using surplus capacity on the AIS that would benefit both AIS and City customers and would, therefore, be in the public interest.

8 ECONOMICS OF THE VARIOUS OPTIONS

8.1 Views of the Participants

The City stated that it carried out a detailed evaluation of three alternatives to meet its future electrical requirements. The first option, favoured by the City, is continued expansion of its generating facilities to supply its firm and reserve requirements up to the year 2003. The second option is to enter into a unit-power contract with Alberta Power for 30 MW of capacity and base-load energy from a portion of the Sheerness power plant and to defer its plant expansion until 1995. The third option is for wholesale power purchase of 30 MW from TransAlta and, again, defer its plant expansion until 1995. The results of the evaluation of the three alternatives, in terms of net present value to the year 2003, are presented in Table 5.

TABLE 5

MEDICINE HAT APPLICATION

ACCUMULATED PRESENT VALUE TOTAL COSTS (MILLIONS OF 1989 DOLLARS)

YEAR	LOCAL GENERATION OPTION	30 MW BASE LOAD PURCHASE FROM TRANSALTA RATE 850	30 MW UNIT POWER PURCHASE FROM ALBERTA POWER
1990	13.5	15.2	18.1
1991	27.1	30.3	35.7
1992	40.8	45.3	52.7
1993	55.4	60.7	69.8
1994	70.8	76.4	87.0
1995	87.2	94.4	106.2
1996	102.7	112.2	124.9
1997	118.1	129.7	143.2
1998	133.2	146.8	160.9
1999	147.7	163.2	177.8
2000	161.7	179.2	194.0
2001	175.6	194.9	209.9
2002	189.2	210.1	225.2
2003	202.4	225.0	240.0

The City estimated the capital cost of its proposed plant expansion to be \$34.6 million (in 1989 dollars). The estimated cost to install Phase I in 1992 is \$17.7 million. The estimated cost to install Phase II in 1996 is \$16.9 million (in 1989 dollars).

TransAlta, Alberta Power, Calgary, Red Deer and Lethbridge, and IPCAA all suggested that, in light of the surplus capacity presently existing on the AIS, there would be benefits to the City if it purchased its reserve requirements from the AIS and deferred Phase I until the 1993-1995 period.

TransAlta presented a proposal for the sale of 30 MW of reserve capacity to the City that would allow Phase I to be deferred upto at least 1993. Transalta suggested that the benefits of a deferral, which were identified as approximately $900 000 per year, could be shared with 85 per cent going to TransAlta and 15 per cent going to the City, although the proposed 85/15 split of benefits is open to further negotiation. TransAlta stated that one of the difficulties in pricing reserve capacity is that, while it costs virtually nothing to provide such reserve, given the current surplus on the system, it has a value which must be adequately captured in any pricing agreement.

The City submitted its analysis of the benefits of deferral, at various levels of splits of benefits between TransAlta and the City, as shown in part in Table 6. On the basis of that analysis, the City concluded that there is insufficient benefit to the City, based on the 85/15 split, to justify deferring the proposed expansion.

The City stated that, while there may be benefits to deferring Phase I, there are also risks associated with such a deferral. The storage costs of equipment already purchased has to be taken into account. Additionally, the City could be exposed to an undue risk of real escalation in capital costs in later years.

Alberta Power stated that it believed there are sufficient benefits in deferring Phase I, but the parties have to reach agreement on an appropriate sharing of the benefits.

8.2 Views of the Board

The Board notes that no one disputed the assessment of the City that, of the three alternatives it evaluated, as set out in Table 5, the local generation option is the least cost option for long-term supply.

However, it notes that the City also calculated the value of benefits attributable to deferring the investment, demonstrating that a deferral of 3 years, after which firm capacity would be required, could be economically advantageous to both parties (see Table 6). The City pointed out that its analysis omitted potential future risks and the cost of storing the unit that has already been purchased. Moreover, any socio-economic benefits that might be generated by the proposal would also be deferred. The Board agrees with Alberta Powers that these associated effects could be handled through negotiating the appropriate allocation of benefits. The Board also recognizes that any deferral would result in the City having to alter its current plans.

TABLE 6

BENEFIT TO THE CITY OF THE NET SAVINGS IN COSTS RESULTING FROM A DEFERRAL OF ITS PROPOSED NEW PLANT (NET PRESENT VALUE IN THOUSANDS OF 1990 DOLLARS)

No. of Years Plant Deferred from 1990 Commissioning	Benefit Split Between the City and TransAlta (the City's Share/TransAlta's Share)				
	100/0%	67/33%	50/50%	15/85%	0/100%
1	$ 982	$ 658	$ 491	$ 147	$0
2	$1896	$1270	$ 948	$ 284	$0
3	$2718	$1821	$1359	$ 408	$0

RESERVE CAPACITY CHARGES THAT WOULD HAVE TO BE PAID BY THE CITY TO TRANSALTA TO REALIZE THE DEFERRAL BENEFITS CITED ABOVE (DOLLARS PER KILOWATT PER YEAR)

Time Period	Benefit Split Between the City and TransAlta (the City's Share/TransAlta's Share)				
	100/0%	67/33%	50/50%	15/85%	0/100%
1990-91	$0	$11.91	$18.04	$30.67	$36.09
1991-92	$0	$12.22	$18.51	$31.47	$37.02
1992-93	$0	$12.11	$18.35	$31.19	$36.70

The Board concludes there could be significant economic benefit from having the AIS provide reserves capacity to the City until about 1993. However, the Board would not view the provision of such capacity as being a normal commercial transaction, recognizing that the transaction might only come about if the Board were to deny the application of the City. Therefore, the Board would expect that any sharing of benefits would reflect the following considerations:

- The City's position that, in the long run, the proposed expansion is the least cost option. This position was not questioned by any of the participants at the hearing.

- The potential benefits are available only if the City defers its proposed expansion.

- This deferral of the City's proposed expansion provides potential benefits only because there is surplus capacity on the AIS at the present time. However, the City is not responsible for the existence of that surplus.

- The City would bear the risks associated with deferral as well as a delay of the associated benefits of its proposed expansion, whereas the AIS would benefit from a deferral of the application at no further cost to the utility members or their customers.

The Board would, therefore, expect that in any agreement, a significant portion of the benefits available from deferral would flow to the City. This portion might be considerbly greater than would normally occur in a commercial transaction.

On the basis of the foregoing, the Board believes that the application should be denied at this time. In turn, the Board would expect that TransAlta and the City would pursue active, sincere negotiations to reach a suitable agreement. If, in 2 to 3 months, an agreement cannot be successfully concluded, the City could then pursue either one of two options: (a) it could apply under section 17 of the Act to obtain orders from the ERCB and PUB that would provide for delivery of reserve capacity by TransAlta at a price that ensures an appropriate sharing of the benefits; or, (b) it could proceed to re-apply to the ERCB for approval of the needed facilities.

9 SUMMARY OF FINDINGS

Having examined the evidence presented by the participants at the hearing, the Board finds as follows:

1. The City's electric system would require additional reserve capacity commencing in 1990. As well, the City's electric system is likely to require additional firm capacity in about 1993.

2. The proposed plant expansion would satisfy the City's immediate need for reserve capacity and would be available to meet firm capacity needs beginning in about 1993.

3. Provided gas prices do not rise at a rate significantly greater than current forecasts, the proposed expansion would appear to be a sound economic choice for long-term supply to the City's system.

4. The proposed expansion would increase reliability of supply to the area but only to a small degree.

5. There is a current surplus of capacity on the AIS, which is likely to persist until about 1993.

6. The potential economic benefit of deferring the proposed expansion for up to 3 years and supplying the City with reserve capacity from the AIS would be about $900 000 per year. Both the City's customers and the AIS customers would gain if an agreement for equitable sharing of these benefits could be reached.

10 DECISION

The Board concludes that it would be more consistent with the objective of economic, orderly, and efficient development and operation of the Alberta electric system if installation of the applied-for facilities was deferred for some 2 or 3 years. Accordingly, the Board denies the application without prejudice.

DATED at Calgary, Alberta, on 7 August 1990.

N. A. Strom, P.Eng.
Vice Chairman

J. P. Prince, Ph.D.
Board Member

R. G. Evans, P.Eng.*
Acting Board Member

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* R. G. Evans, P.Eng. was unavailable for signature but concurs with the contents and with the issuing of this report.

APPENDIX

GLOSSARY OF TERMS

One-System Planning

One-system planning is defined as the co-ordinated planning process for the provincial electric system as carried out by the Electric Utility Planning Council (EUPC) which encompasses load forecasting, demand-supply management, and generation and transmission planning for that portion of the provincial electric system supplied by and dependent upon the members of the EUPC. The process includes consideration of interconnections with intra- and extra-provincial utilities, including Medicine Hat's electric utility, British Columbia Hydro and Power Authority (B.C. Hydro), and Saskatchewan Power Corporation (Sask. Power). As well, it includes the consideration of the impact of private generators, such as Syncrude, that are connected to the system.

Alberta Interconnected System (AIS)

The AIS is defined as that portion of the provincial electric system served by and dependent on the generation and bulk transmission facilities of the three generating utilities, Alberta Power, Edmonton, and TransAlta. This includes the distribution systems of their major municipal utility customers, Calgary, Lethbridge, and Red Deer.

The relationship between the generating utilities is determined through a series of agreements. The day-to-day operations of the AIS are determined by the terms of the power pool agreement and customer contractual agreements. Longer-term arrangements, such as reserves sharing, are determined through a reserves-sharing agreement and appropriate financial arrangements. Customer relationships are handled by the serving utility through service contracts.

Electric Utility Planning Council (EUPC)

The EUPC is an inter-utility organization which carries out co-ordinated, one-system planning for the Alberta electric system. In order to carry out this function, the EUPC performs two roles. The first includes the technical planning activities involving load forecasting, establishment of reliability and economic evaluation criteria, and generation and transmission planning. The second role is to provide a forum for the utilities and other interested parties to exchange information concerning electric planning for the province. The members of the EUPC are the generating utilities (Alberta Power, Edmonton, TransAlta, and the City of Medicine Hat), and the larger distribution utilities (the cities of Calgary, Lethbridge, and Red Deer).

Reserve Sharing Agreement

A Reserve Sharing Agreement is an agreement between generating utilities whereby each agrees to purchase its deficiency in capacity reserves from each other's surplus reserves, if available. Such an agreement exists between Alberta Power, Edmonton, and TransAlta. In the context of this hearing, a short-term agreement also exists between TransAlta and Medicine Hat which provides Medicine Hat with reserve capacity from TransAlta's system.

Interconnection Agreement

Interconnection Agreement is an agreement between interconnected utilities whereby each agrees to mutually assist the others during the course of operations, especially during abnormal operating conditions. Such agreements currently exist between TransAlta and B.C. Hydro and between Alberta Power and Sask. Power. An informal understanding exists between Medicine Hat and TransAlta respecting mutual assistance during abnormal conditions.

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

ALTEX RESOURCES LTD. — Decision D 90-6
BITTERN LAKE GAS PROCESSING PLANT — Application 891425

1 INTRODUCTION

1.1 Application

Altex Resources Ltd. (Altex) applied, pursuant to section 26 of the Oil and Gas Conservation Act, for approval to modify the existing Bittern Lake sweet gas plant, located in legal subdivision 11 of section 27, township 46, range 21, west of the 4th meridian (11-27), to allow for the processing of sour gas. The modified plant would be designed to process a maximum of 305.0 thousand cubic metres per day (10^3 m^3/d) of raw gas from which 286.0 x 10^3 m^3/d of sales gas and 10.6 m^3/d of liquefied petroleum gases (LPG mix) would be recovered. At the maximum raw gas inlet rate, a maximum of 0.62 tonnes per day (t/d) of sulphur dioxide (SO_2) (0.31 t/d sulphur equivalent) would be emitted to the atmosphere from a flare stack 12.2 metres in height.

1.2 Hearing

The application was originally scheduled to be considered at a public hearing in Camrose, Alberta, on 16 January 1990. However, a pre-hearing meeting was held in Calgary, Alberta, on 15 January 1990 to consider a request by the City of Camrose that the hearing be adjourned until a water impact study could be conducted.

Consequently, the adjournment was granted and the Altex application was considered at a public hearing in Calgary, Alberta, on 22, 23, and 26 February 1990 by F. J. Mink, P.Eng. (Chairman), Dr. B. F. Bietz (Board Member), and K. G. Sharp, P.Eng. (Acting Board Member). Those who participated at the hearing are listed in the following table.

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Altex Resources Ltd. (Altex) H. R. Hansford	D. K. Slessor, P.Geol. M. M. Kirzinger, P.Eng. E. H. Toews, P.Eng. all of Altex Resources Ltd.

THOSE WHO APPEARED AT THE HEARING (cont'd)

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Altex Resources Ltd. (cont'd) (Altex)	J. K. Farries, P.Eng. of Farries Engineering (1977) Ltd. R. B. Lowndes, P.Eng. of Genesis Engineering Ltd. J. S. Goudey, Ph.D. of HydroQual Canada Limited D. M. Leahey, Ph.D. of Western Research G. J. Boehm, P.Eng. J. Thompson, P.Geol. both of D&S Petroleum Consulting Group Ltd.
Northstar Energy Corporation (Northstar) D. A. Holgate	R. B. Pardy, P.Eng. N. H. Antonenko K. W. Spinner, P.Eng. M. D. Weatherhead, P.Eng. P.J.M. Hood, P.Geol. all of Northstar Energy Corporation K. R. Damberger, P.Eng. of Bower Damberger Rolseth Engineering Ltd. F. Schorning, P.Geol. R. E. Hughes, P.Eng. both of McDaniel & Associates Consultants Ltd.
The City of Camrose (City) J. Timinski	J. Timinski of the City of Camrose E.A.D. Allen, Ph.D. of E.A.D. Allen, Aquatic Consulting
Erehwon Exploration Limited (Erehwon) J. C. Crawford, Q.C.	E. J. Pinchin, P.Geoph.
North Canadian Oils Limited (NCO) L. A. Wahl	L. A. Wahl, P.Eng.

THOSE WHO APPEARED AT THE HEARING (cont'd)

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Energy Resources Conservation Board staff	
L. S. Fillion, R.E.T.	
M. T. Pittman	
F. Rahnama, Ph.D.	
M. Pinney	
P. B. Cupido	
L. A. Samson, C.E.T.	

2 BACKGROUND

Altex has sour gas reserves in the Bittern Lake area and purchased an existing sweet gas plant at 11-27 with intention to modify the plant to process and market its reserves. Altex indicated that protracted negotiations with Northstar had not resulted in an acceptable processing agreement. Altex maintained that its processing costs would be significantly lower than the best offer to process its gas at a Northstar facility in the area. Use of the Northstar facility would require a new pipeline connection across the Battle River.

Northstar, however, claimed that its 5-31-45-20 W4M (5-31) plant was already designed to process sour gas and currently had spare capacity. Northstar contended that there was no need to construct a second sour gas processing plant in the area and maintained that it was prepared to expand its 5-31 plant to handle the Altex gas volumes.

3 ISSUES

The Board considers the issues to be

- reserves available for processing in the area,
- economic impacts and relative merits of the Altex and Northstar processing alternatives, and
- environmental impacts.

4 RESERVES AVAILABLE FOR PROCESSING

4.1 Views of Altex

The principal reserves held by Altex in the area occur in the Ellerslie D Pool (D Pool). Altex interpreted the Upper Ellerslie Sand in the Bittern Lake area to have been deposited as a widespread nearshore marine sand in a flood-tidal deltaic complex and not as a fluvial channel. It was Altex's position that the trend of the sand generally runs in a NNW-SSE direction across the D Pool and extends well to the south of the pool.

Altex stated the main wells that help to define the trend are all in 46-21 W4M: 9-22, 12-23, 15-15, 12-14, 12-1, and 16-1. The trapping mechanism for the gas in the D Pool, which consists of the wells 12-14, 15-15, 9-22, and 12-23, was a shale barrier. Figure 1 shows the applicant's net pay map of the D Pool.

Altex argued that a number of wells have totally or partially penetrated the shale channel and help to define its position. These are 16-1, 16-5, 4-8, 10-14, 10-19, and 1-23, all in 46-21 W4M; also 7-7-46-20 W4M and 16-34-45-21 W4M. On the east side of the D Pool, Altex stated that the shale barrier separates the gas in the pool from the updip wet wells in 10-13 and 13-24. On the south side of the pool, it stated that the shale barrier separates gas in the pool from the updip wet wells in 6-4, 7-5, and 7-6; in 46-20 W4M; and 12-1 and 16-1 in 46-21 W4M. On the north side of the pool, Altex argued that the shale barrier separates gas in the pool from the updip wet wells at 7-26 and 11-27, while the westerly limit of the pool was a gas/water interface. In its opinion, the control wells that define the reservoir for the downdip water line are 8-3, 12-10, and 10-21, all in 46-21 W4M. Upon cross-examination, Altex stated that Ostracod sands had been recognized in the area and as a result the Ellerslie reservoir was picked on the second sand below the Ostracod lime in the 8-3 and 10-21 wells.

Altex did not utilize geophysical data in the positioning of the shale channel; however, given that AOF pressure data indicated no boundary effects for a drainage radius of 540 metres, Altex placed the shale channel more than half a kilometre (km) away from the 12-23 well.

Altex indicated a 12 per cent density porosity cutoff was used to determine net gas pay. This cutoff was determined from the upper 3 metres of the Ellerslie Sand in the 9-22 well. The well logs for this zone indicate clean Gamma Ray, good Spontaneous Potential (SP), and excellent Microlog separation. Altex interpreted the gas/water interface at -481.0 metres and this elevation was determined from geophysical logs from the four wells in the D Pool.

Altex retained D&S Petroleum Consulting Group Ltd. (D&S) to complete an independent study of the D Pool; however, Altex defended and utilized its own calculations throughout the hearing. In that regard, Altex estimated the proved and probable initial established marketable gas reserves of the D Pool at 656 x 10^6 m^3 (23.3 Bcf) and 637 x 10^6 m^3 (22.6 Bcf), respectively, for a total reserve of 1293 x 10^6 m^3 (45.9 Bcf). D&S estimated the proved and probable reserves at 497 x 10^6 m^3 (17.6 Bcf) and 143 x 10^6 m^3 (5.1 Bcf), respectively, for a total pool estimate of 640 x 10^6 m^3 (22.7 Bcf). The proved portion of the above estimates reflected the respective isopacheous interpretations of the pool under sections 14, 15, 22, and 23-46-21 W4M. On an engineering basis, D&S stated that its examination of the radii of investigation for the four wells in the D Pool indicated gas in place consistent with its volumetric analysis from geological mapping.

4.2 Views of Northstar

Northstar interpreted the Upper Ellerslie Sand of the D Pool to have been deposited in a fluvial channel system. A shale channel forms the trap for the gas.

Northstar stated that the D Pool is delineated by the four cased gas wells and by two dry holes in 10-14 and 1-23-46-21 W4M. It noted that the 1-23 well encountered a shale channel which forms the trap for the D Pool on the eastern boundary. Figure 2 shows Northstar's net pay map for the D Pool. Northstar argued that offsetting wells (10-21, 13-24, 7-26, and 11-27, all in 46-21 W4M) have wet regional Upper Ellerslie sands at the same stratigraphic and structural position to the D Pool pay zone. Accordingly, Northstar reasoned that these wells were separated from the D Pool by the shale channel, which was drawn halfway between the proven gas wells and those wet wells.

Northstar indicated that the southern boundary lacks well control but since the stepout well 10-14 had no pay and was within 0.8 km of 12-14, then the pool edge should be at least 0.8 km from the 12-14 and 15-15 wells. In Northstar's interpretation the southern boundary was placed 1.1 and 1.2 km from the 12-14 and 15-15 wells, respectively. The structure map was used by Northstar as a guide to the positioning of the shale channel. This resulted in a proposed zero pay contour which followed the edge of the shale plug for the north, east, and south limits. The western limit of the pool was defined by the structure elevation of a gas/water interface which was based on the structure porosity map.

Northstar used a 15 per cent density porosity cutoff for reserve determination. It indicated that for reserve calculation purposes gas/water contact for the pool is assumed at -481.3 metres; however, the transition zone in the 12-23 well probably did not have any reserves.

Northstar retained McDaniel & Associates Consultants Ltd. (McDaniel) to complete an independent study of the D Pool. McDaniel's interpretation of the D Pool supported the Northstar position. Northstar estimated the proved initial established marketable gas reserves of the D Pool at 274 x 10^6 m^3 (9.7 Bcf), which was supported by McDaniel's estimate of 272 x 10^6 m^3 (9.7 Bcf). Both estimates reflected isopacheous interpretations of the pool which were, for the most part, wholly contained within sections 14, 15, 22, and 23-46-21 W4M, and neither estimate included a probable reserves portion.

Northstar also submitted gas reserve estimates for other properties in the Bittern Lake area. It believes that the same properties identified by Altex represent marketable reserves of only 451 x 10^6 m^3 (16 Bcf), compared to some 1103 x 10^6 m^3 (39 Bcf) identified by Altex. McDaniel generally supported the Northstar estimate of other reserves in the area.

4.3 Views of Erehwon and NCO

Neither Erehwon nor NCO commented on the geological interpretation of the D Pool. However, both companies suggested that there were sufficient reserves in the general area, in addition to the Altex reserves, to justify regional increased processing capacity.

Erehwon stated that the volume of reserves available for processing was directly related to the cost of having those reserves processed. Consequently, lower processing fees would have the effect of increasing the reserves that could economically be produced.

Because of the higher Northstar processing fees and the cost of transporting gas across the Battle River, Erehwon suggested that there were reserves which could be produced to the proposed Altex plant but which could not be economically produced to the Northstar plant. Therefore, the reserves estimates could differ depending on which processing alternative was ultimately approved.

4.4 Views of the Board

The Board notes that the geological interpretations of Altex and Northstar with respect to the D Pool result in substantially different reserve values. The limits of the pool in the north, east, and west directions are quite similar. However, the southern shale boundary as drawn by Northstar was positioned only on the basis of an arbitrary stepout distance and in the Board's opinion failed to take into account the geological data from the wells in sections 1, 2, 3, and 10-46-21 W4M. Therefore, the areal extent of the pool as interpreted by Northstar appears to be overly conservative. The Board agrees with Altex that the geological data from those wells indicate that the Upper Ellerslie Sand extends the pool farther to the south. Although Altex did not assign

proven pay south of sections 14 and 15, the contouring style of their net pay map reflects an interpretation that the pool continues south of the proven sections. The Board believes that the areal extent of the pool as presented by Altex is a more reasonable interpretation.

The Board also notes that the effect of the different estimates of density porosity cutoff on net pay, as derived from geophysical logs, contribute to the significantly different reserve estimates by the two companies. Upon review of the geophysical log evidence in the 9-22 well the Board is of the opinion that the Gamma Ray, SP, and Microlog responses used by Altex, rather than just the neutron response used by Northstar, indicate that the 12 per cent density porosity cutoff is valid. Based on a 12 per cent cutoff, the Board finds the net pay values suggested by Northstar for the wells 9-22 and 12-23 to be overly conservative, and finds the Altex net pay values to be more reasonable.

Considering the evidence, the Board estimates the proved initial established marketable gas reserve of the D Pool to be 599×10^6 m^3 (21 Bcf) which is in reasonable agreement with the proved portion of the Altex estimate (656) and the proved plus probable estimate of D&S (640). A review of other reserves booked in the area also tends to confirm the estimate submitted by Altex.

5 ECONOMIC IMPACTS AND RELATIVE MERITS OF THE ALTEX AND NORTHSTAR PROCESSING ALTERNATIVES

5.1 Views of Altex

Altex stated that the first well completed in the D Pool, 12-23-46-21 W4M, was drilled during September 1988. As a result of this highly productive gas well, additional drilling was conducted and now four wells have been completed in the D Pool. Altex believes that the proved marketable gas reserves from the D Pool alone could support sustained production of 163×10^3 m^3/d.

In addition to its own reserves, the applicant stated that Canadian Occidental Petroleum (Can Oxy), Canada Northwest Energy Limited (CNWE), and BP Canada Inc. (BP) had all inquired about sour gas processing capacity for wells north of the Battle River. Additionally, NCO had recently approached Altex regarding its sour gas processing needs. Based on the applicant's sour gas processing requirements and those of other producers north of the Battle River, Altex was confident that there is a significant need for additional processing capacity in the area.

Altex stated that the processing alternatives which it considered included expansion and modification of the existing 11-27 sweet gas plant and use of Northstar's 5-31 sour gas plant and Mobil Oil Canada's

(Mobil) 3-32-45-21 W4M (3-32) sour gas plant. Mobil was contacted by the applicant but was unable to offer any processing capacity and was unwilling to expand its facility. Altex considered the Northstar 5-31 facility as the most likely option for processing its sour gas reserves and initiated negotiations with Northstar during late 1988. Altex indicated that despite several months of ongoing negotiations to gain access to the Northstar facility, it was unable to reach a firm processing arrangement at an acceptable fee. Altex advised Northstar that it was evaluating the 11-27 plant expansion alternative and requested Northstar's best possible processing offer. Altex viewed Northstar's best offer as unacceptable and purchased the 11-27 plant in October 1989.

In addition to offering a more economic processing alternative for its own reserves, Altex stated that expansion of the 11-27 facility would allow the economic processing of certain reserves north of the Battle River which could not economically be gathered and processed at Northstar's 5-31 plant because of higher transportation and processing fees associated with the 5-31 facility. As well, a portion of the gas to be processed at the 11-27 plant requires delivery to Northwestern Utilities Limited (NUL). Altex indicated that its facility would have both NOVA CORPORATION OF ALBERTA (NOVA) and NUL sales lines, a service currently not available at the Northstar 5-31 plant. Altex stated that if its gas was to be processed at Northstar's 5-31 facility, because of contractual arrangements with NUL, a portion of the 5-31 plant's sales gas delivered to NOVA would require transportation to the NUL system which would result in an incremental fee.

Altex indicated that it discounted Northstar's 5-31 facility as a viable processing alternative after it was unable to obtain a competitive processing arrangement when compared to the 11-27 plant expansion. Altex did concede that Northstar's fees likely reflect the actual operating costs encountered at the 5-31 plant. However, it speculated that Northstar's gas sweetening process at the 5-31 plant may be less efficient and more expensive to operate than Altex's proposed expansion, and this may contribute to the higher process fee.

Altex felt that expansion of the 5-31 plant would fail to provide adequate processing capacity for the gas reserves in the area, and argued that utilization of the 5-31 plant would require a lengthy river crossing at a cost of $250 000.

Altex submitted detailed analyses examining the economics of processing its gas at an expanded 11-27 plant as compared to the 5-31 Northstar facility. It considered a number of scenarios for both proposed plant expansion cases, varying plant size, throughput and, in some cases, imposing capacity constraints. In every case, however, Altex considered the impact of each proposed expansion only as it affected its own economics. No attempt was made to examine the effect of either plant expansion on the economics of other area producers.

Based on its evalutions of these two projects, Altex concluded that the absolute minimum incremental value of the 11-27 plant expansion was nearly \$3.7 million before tax while the after tax value is some \$2.4 million. If the 5-31 plant did install facilities for LPG mix recovery, Altex calculated the absolute minimum incremental value of the 11-27 plant to be just over \$3 million.

Altex indicated that it was prepared to custom process gas from other producers in the area for \$12.42/10^3 m^3 (\$0.35/Mcf), a net saving of some \$5.33/10^3 m^3 (\$0.15/Mcf) over the Northstar offer of \$17.75/10^3 m^3 (\$0.50/Mcf). Further, Altex submitted that lower processing fees at the expanded 11-27 plant would generate between 2.3 to 2.7 million dollars in higher royalty payments to the Crown.

Altex argued that approval of its application would not represent a proliferation of gas processing plants in the area since the 11-27 plant already exists. It believed that its proposal would optimize the economic life of the 11-27 plant since it is currently severely under-utilized. Altex concluded that approval of this application would allow for the continued production of the small amount of sweet gas reserves which is currently tied in and processed at the 11-27 site and would provide for the most efficient, economic, and orderly development of other gas reserves in the area.

5.2 Views of Northstar

Northstar suggested that in considering the Altex application, the Board should decide whether there was a need for additional processing capacity in the area, what degree of additional capacity could reasonably be utilized in the long term, and what was the most appropriate location for that additional capacity.

Northstar accepted that there was a need for additional sour gas processing in the area. However, it stated that having regard for the existing spare capacity in its 5-31 plant, declining production from existing wells, Altex's processing requirements, the needs of other producers, and making allowance for future development, a maximum of 141×10^3 m^3/d of additional capacity was all that could reasonably be justified.

Northstar stated that the size of a processing plant should be directly related to the estimated reserves in an area. Northstar cautioned that an overly optimistic assessment of the reserves would result in idle capacity, higher unit operating costs, and loss of economically producible reserves due to early turndown/abandonment of existing and proposed processing facilities.

Northstar stated that approval of Altex's application for an additional 305×10^3 m^3/d of sour gas processing capacity was not justified and would have potentially serious adverse impacts on Northstar and its

partners, as well as on the Crown and the public. Specifically, Northstar suggested that unless additional reserves were tied in, the volume of unutilized capacity in its 5-31 plant would continue to increase over the next 3 to 5 years until the plant could no longer operate. Northstar estimated that premature shutdown of its plant could result in the loss of approximately 30 x 10^6 m^3 (1.1 Bcf) of recoverable gas reserves and the royalty revenue associated with those gas volumes. Additionally, lower plant throughput would result in higher unit operating costs to the producers which in turn would reduce the revenue available for further exploration and development in the area. Northstar contended that expansion of its 5-31 plant was preferable to the Altex proposal since it would provide sufficient processing capacity to meet the needs of area producers, would allow the 5-31 plant to operate closer to its capacity for a longer period of time, and would contribute to lower operating costs.

Northstar presented two separate economic evaluations showing the impact, on all area producers, of expanding the 11-27 plant versus expanding Northstar's 5-31 plant, as well as its assessment of the impact of the two plant proposals on Altex only.

Because both Altex and Northstar disagreed on the level of reserves available for processing, Northstar ran its economics using both its own lower reserve estimate and the higher reserve estimate presented by Altex. Using Northstar's own reserve estimates of 274 x 10^6 m^3 (9.7 Bcf) of marketable reserves in the D Pool, the company calculated that its proposal has an overall net benefit of \$2.4 million. Under this scenario, Altex achieves a slight economic advantage despite foregoing approximately \$1.8 million in processing fees. If Altex's reserve estimates of 656 x 10^6 m^3 (23.3 Bcf) were used, Northstar calculated that while its proposal has an overall net benefit of \$2.2 million, Altex is worse off by approximately \$2.0 million. Northstar concluded that if the reserves available to Altex are greater than 507 x 10^6 m^3 (18 Bcf), then expansion of the 11-27 plant would be more economically attractive to Altex than its proposal.

Northstar also suggested that expansion of its 5-31 plant was consistent with the Board's policy respecting plant proliferation. Specifically, expansion of the Northstar plant would result in consolidation of sour gas processing facilities, would prevent a second source of SO_2 emissions, and would potentially result in the elimination of existing SO_2 emissions. This latter case would occur only if Northstar was able to qualify for provincial funding for a scheme to reinject acid gas.

Northstar also suggested that the Board's policy to prevent plant proliferation required an applicant to conduct an exhaustive review of the processing alternatives before submitting an application for additional processing capacity. It was Northstar's opinion that although the Altex review of the Northstar option had been time consuming, it had

not been exhaustive. Northstar advised that it had made several offers to Altex for which no counter offer was ever received. Further, Northstar's proposal to submit the problem to binding third-party arbitration was refused by Altex. Northstar stated that the negotiation process had been one-sided and maintained that Altex's unrealistic expectations with regard to processing fees had eliminated the likelihood of serious negotiations.

5.3 Views of Erehwon and NCO

Erehwon indicated that it had shut-in reserves in the vicinity of both the Northstar and Altex plants and agreed that there was a need for additional processing capacity in the area. It suggested that the lower process fees offered by Altex would permit tie-in of marginal wells that otherwise would be uneconomic to produce, and would extend the economic life of wells already on production. The lower fees would generate additional royalty revenue from incremental production. Additionally, Erehwon claimed that lower process fees would provide added economic incentive for exploration and drilling in the area. Therefore, Erehwon stated that it supported the Altex application.

Erehwon expressed confidence that the fees proposed by Altex were both realistic and consistent with the fees charged by other sour gas plant operators in the general area. With respect to the Northstar processing alternative, Erehwon indicated that it had wells tied in to the 5-31 plant and was aware of the existing fee structure and operational practices at the plant. Erehwon noted that spare capacity was available in the 5-31 plant but access to that capacity was restricted because of high line pressures and a bottleneck in the eastern leg of the gathering system.

Erehwon speculated that denial of the Altex application would likely result in tie-in of the Altex gas to the Northstar plant. In that event, the 5-31 plant would be operating up to capacity, thus precluding any debottlenecking of the eastern leg of the gathering system and effectively eliminating all access to the plant on a "best-efforts" basis.

In conclusion, Erehwon stated that it believed there was a need for additional sour gas processing capacity and believed that there are sufficient reserves in the area to maintain both the Northstar plant and the proposed Altex plant.

Erehwon did not consider the Board's plant proliferation policy to be at issue, and contended that denial of the Altex application would serve to create a processing monopoly and eliminate competition. In Erehwon's opinion, competition between plant operators would result in lower processing fees, which would be advantageous for both the Crown and third-party producers.

NCO stated that it was an active operator in the area and its primary focus was to direct exploration attempts to areas where it could be assured processing capacity or gain a working interest in a facility. Once plant and gathering facilities were in place, NCO would pursue further development.

After its initial discovery in the Bittern Lake area, NCO had approached Northstar but was unable to obtain an equity position in the plant. Northstar had indicated that it would process the NCO gas on a fee basis; however, NCO would be responsible for construction of a gathering system across the Battle River. This option was not acceptable to NCO.

Subsequently, NCO had approached Altex and was offered an ownership position in an expanded 11-27 plant. NCO considered the Altex proposal to be the most cost-effective processing alternative and stated that it intended to pursue further reserves development in the area.

5.4 Views of the Board

Given its analysis of reserves, the Board accepts that there is a need for additional processing capacity in the Bittern Lake area. With respect to the location of such facilities, the Board notes that Altex's proposed scheme would make use of the existing 11-27 plant site although significant modifications would be required in order to process sour gas. Similarly, the Northstar proposal would necessitate physical modification of the existing 5-31 plant in order to accommodate the increased gas production. From this perspective, there is no significant difference between the Altex and Northstar processing alternatives.

With respect to the issue of plant proliferation, the Board's objective is to avoid unnecessary duplication of processing facilities, to encourage the use of existing facilities and infrastructure wherever practical, and to ensure that new facilities are appropriately sized having regard for the needs of all area producers. The policy is not specific to sour gas processing plants and should not be construed as an attempt to alter the ratio of sour versus sweet processing schemes. Additionally, the policy is not intended to create processing monopolies or prevent the construction of new facilities without regard for economic impacts.

In comparing the economics of the two schemes, Altex demonstrated that an 11-27 plant expansion would be the most profitable option, from the company's own position as well as that of others who would utilize the facilities at significantly lower processing fees than offered by Northstar. Although Northstar questioned Altex's economics and identified its 5-31 plant expansion as the lowest cost processing option for area producers as a whole, the Board concluded that those economic findings hinged largely on Northstar's conservative estimate that area reserves would not support development of two sour gas facilities. The

Board cannot support Northstar's view that throughput at the 5-31 plant would decline rapidly over the next 5 years if the Altex plant expansion is permitted. The Board tends to accept the evidence that there are additional natural gas reserves in the area, in addition to the D Pool, that will require processing in the future, and believes that the existing 5-31 facility could be utilized at a reasonable capacity level for some time to come.

In summary, the Board accepts that there is a need for additional processing capacity in the Bittern Lake area and notes that both the Altex and Northstar processing alternatives would make use of existing facilities. Considering the reserves in the area, the Board does not believe that the Bittern Lake expansion will necessarily result in significant idle plant capacity at either facility.

While the Board is not able to determine the exact value of the fee structure at the Altex plant, it is convinced by the evidence that third-party processing fees will be notably lower than those available from Northstar. Therefore, the Board considers the Altex proposal to be economically superior. The Board also expects the Altex plant expansion will ultimately increase the net royalty payments to the Crown and could offer a modest conservation benefit by allowing the recovery of currently marginal gas.

6 ENVIRONMENTAL IMPACTS

6.1 Views of Altex

Recognizing that the City of Camrose had concerns regarding the emissions from the proposed 11-27 plant expansion, Altex retained Dr. Leahey of Western Research to perform an independent assessment of the impacts of the proposed Altex development. His assessment addressed both air quality and sulphate deposition effects from sulphur emissions from the Mobil, Northstar, and modified Altex facilities. The study predicted that SO_2 emissions from these sources in the Camrose and Driedmeat Lake area would result in maximum hourly ground-level concentrations of 0.015 parts per million (ppm), approximately one-tenth of Alberta's maximum permissible hourly level of 0.170 ppm. Dr. Leahey noted that this SO_2 standard is also protective of aquatic environments such as Driedmeat Lake. He found sulphate deposition levels from all three plants would be about 1 kilogram per hectare per year in the area of Camrose and Driedmeat Lake. Dr. Leahey stated that this deposition is very small when compared to the background sulphate levels for this area.

Altex retained the services of HydroQual Canada Limited (HydroQual) to assess the potential impacts from the proposed 11-27 plant expansion on the water quality of Driedmeat Lake. HydroQual's study took into account the existing sulphate loading within the catchment area of Driedmeat Lake and compared the existing loading to the future sulphate loading should

the Altex application be approved. In addition to a number of water quality analyses performed over the years on Driedmeat Lake and tributary rivers and creeks, the study also took into account lake area, volume, mean depth, and seasonal variations in lake flushing times. The HydroQual study concluded that the additive emissions of sulphur compounds due to the Altex proposal would have no measurable impact on the sulphate concentration or pH of Driedmeat Lake and therefore would create no impact on the water supply for the city of Camrose. HydroQual stated that the sulphate levels in the city's raw water supply are well below the taste threshold which is between 200 to 500 milligrams per litre.

Regarding the City's recommendation that sulphur emission abatement equipment be incorporated at its proposed 11-27 expansion, Altex stated that its proposed emissions of 0.31 t/d are well below the level at which sulphur recovery is required as per the current sulphur recovery guidelines.

Altex stated it would meet or exceed all current guidelines and regulations with respect to its application and therefore concluded that the proposed 11-27 plant expansion would have no adverse impacts on Driedmeat Lake or on the city of Camrose. Altex also noted that the Northstar proposal would require a pipeline crossing of the Battle River which would have an incremental environmental impact.

6.2 Views of Northstar

Northstar indicated that it was aware that the previous owner of the 5-31 plant had conducted soil and water quality monitoring of Driedmeat Lake for several years as part of a condition on the plant approval, although it could not comment on the results of that monitoring program. Northstar pointed out that Alberta Environment had waived the reporting requirements in 1985/86. Further, the 5-31 plant was operating well within the requirements set out in its Clean Air and Clean Water Act licences.

Northstar advised that it would be prepared to prevent all sulphur emissions by reinjection of the acid gas from its plant if the Altex gas was tied in. Northstar argued that the Altex scheme did not include provisions for reducing SO_2 emissions and consequently, processing of the Altex gas at an expanded 5-31 plant would be preferable from an environmental perspective. Although the 5-31 plant is presently licensed to flare acid gas and emit SO_2, Northstar reasoned that the tie-in of Altex's gas to its 5-31 plant afforded an opportunity to pursue a reduction of emissions. Northstar stated that current government policy aims at reducing SO_2 emissions and in future emission standards would likely become more stringent. If the Altex scheme were approved, it would be considerably more expensive to reduce emissions from two plants than at an expanded 5-31 plant as Northstar proposed.

Northstar admitted that installation of its proposed acid gas injection scheme was contingent upon gaining government assistance through the Sulphur Emissions Control Assistance Program (SECAP). It stated that if SECAP assistance could not be obtained, the Northstar and Altex processing alternatives would be equivalent from the perspective of total SO_2 emissions. However, Northstar argued that its scheme would not result in an additional source of SO_2 but rather a consolidation of sour gas processing facilities in the Bittern Lake area.

6.3 Views of Erehwon and NCO

Erehwon implied that the Altex proposal is not likely to contribute any measurable concentration of sulphate to Driedmeat Lake. It argued that sewage disposal and recreational use of the lake were more likely to be sources of contamination, and NCO supported that view.

6.4 Views of the City of Camrose

The city of Camrose (pop. 15 000) indicated that it derives its potable (drinking) water from Driedmeat Lake. The lake is an enlargement (reservoir) of the Battle River and is located 12 km south and east of the city and a similar distance from the proposed Altex plant site. The City intervened in the Altex application as a result of concerns regarding the impacts of sulphur deposition on water quality in Driedmeat Lake and argued that current air emission standards would not adequately protect its water source.

In support of its concerns, the City filed a report by Dr. E.A.D. Allen on existing and predicted water quality. Dr. Allen confirmed that water quality in Driedmeat Lake was already very poor and, despite the recent investment of some $18.5 million for a new water treatment and supply system, the water continued to have significant taste and odour problems. Dr. Allen noted that sulphate at sufficiently high levels could impart taste and odour. He indicated that at least one sample of treated water showed high sulphate levels, and suggested that it was important that Driedmeat Lake not receive any further inputs of pollutants.

In his report and subsequent testimony, Dr. Allen confirmed that current water quality problems in Driedmeat Lake are primarily a function of high nutrient inputs from agricultural runoff and upstream sewage discharge. This, plus the shallowness of the lake, provided ideal conditions for large blooms of algae and other aquatic plants in the lake. During the winter, decomposition of these plant materials results in severely reduced oxygen levels, associated fish kills, and taste and odour problems. Dr. Allen testified that he agreed with the methodology used by Dr. Goudey of HydroQual in his assessment of water quality in the lake as it would be affected by the Altex plant, and with Dr. Goudey's predictions. He also testified that current taste and odour problems at Camrose appeared to be a product of the release of chemical compounds

from the decomposing plant material, rather than sulphate. He indicated the high sulphate load occasionally recorded in the treated water was possibly from the floculation system installed at the treatment plant.

6.5 Views of the Board

The Board accepts that the Northstar proposal could reduce overall SO_2 emissions in the area if its acid gas injection scheme were implemented. However, given the terms of the SECAP program, it is doubtful that the Northstar plant would qualify for assistance. More likely, the plant would continue to flare its acid gas stream.

Although the Board is satisfied that a satisfactory river crossing could be achieved, it believes the Altex gas plant expansion does offer a very modest environmental advantage since it would eliminate the need for any disturbance of the river.

The City of Camrose's concerns regarding the water quality of Driedmeat Lake and its catchment area are understandable; however, the Board could find no evidence to suggest that the poor water quality of the lake is a result of SO_2 emissions from sour gas plants in the area. The testimony of both water quality experts appears to confirm this view. The Board notes that all existing and future plants are required to comply with Alberta Environment's Air Quality Guidelines and these guidelines are designed to be protective of water bodies such as Driedmeat Lake.

The Board recommends that the City contact Alberta Environment and apprise itself of the results of the soil and water monitoring programs carried out for Driedmeat Lake prior to 1985/86.

The Board notes that the maximum sulphur inlet of 0.31 t/d at the proposed Altex plant is well below the 1 t/d level at which sulphur recovery is mandatory. It believes that no adverse environmental impacts would result from Altex's applied-for plant expansion. The Board accepts Altex's plant design as its proposed flare stack is of sufficient height to ensure compliance with the Air Quality Guidelines, and the conservation aspects of its plant are satisfactory.

7 CONCLUSIONS

Based on the evidence, the Board is satisfied that sufficient reserves exist such that additional sour gas processing capacity is required in the Bittern Lake area for production north of the Battle River. The Board concludes that additional reserves in the area of the Northstar plant should allow it to continue operation for some time. The Board believes that Altex's proposal to expand the existing 11-27 facility represents the most economic and orderly proposal and would result in a minimum amount of surface disturbance. Although Northstar's plant

expansion option would accommodate Altex gas volumes, it does not appear to reflect the reserves or the processing requirements of other producers in the area. The Board expects that the proposed 11-27 expanded plant would operate in compliance with the provincial emission limits set by Alberta Environment and that no adverse impacts would occur to Driedmeat Lake. The Board is therefore satisfied with the technical, conservation, and environmental aspects of Altex's proposal.

8 DECISION

Subject to receipt of the required approval of the Minister of the Environment with respect to environmental matters, the Board is prepared to issue an approval to Altex Resources Ltd. for the expansion and modification of the 11-27 plant as detailed in its Application 891425.

ENERGY RESOURCES CONSERVATION BOARD

DATED at Calgary, Alberta, on 18 May 1990.

F. J. Mink, P.Eng.
Board Member

Dr. B. F. Bietz
Board Member

K. G. Sharp, P.Eng.
Acting Board Member

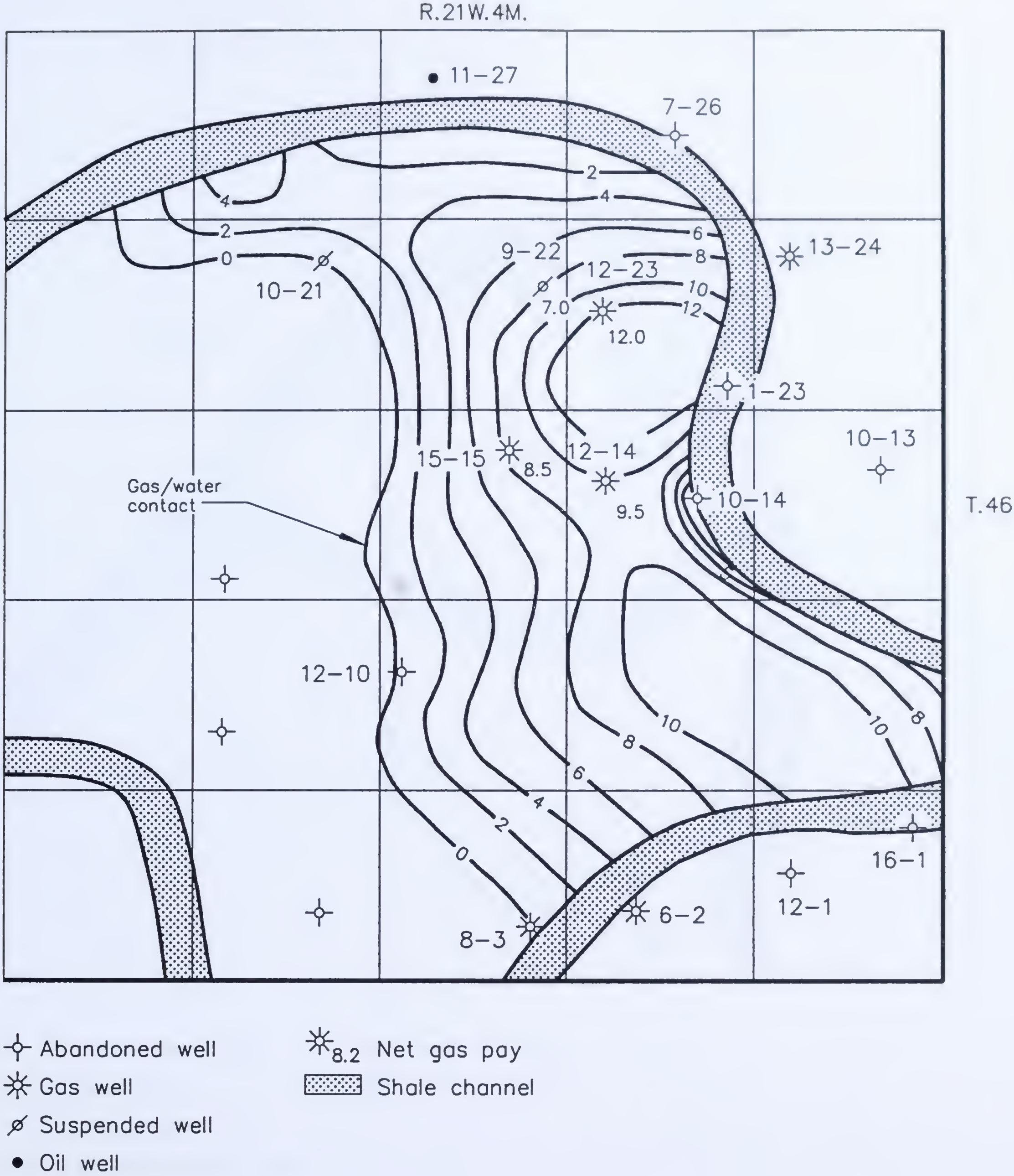

Figure 1 Altex's Net Gas Pay – Ellerslie D Pool

ERCB

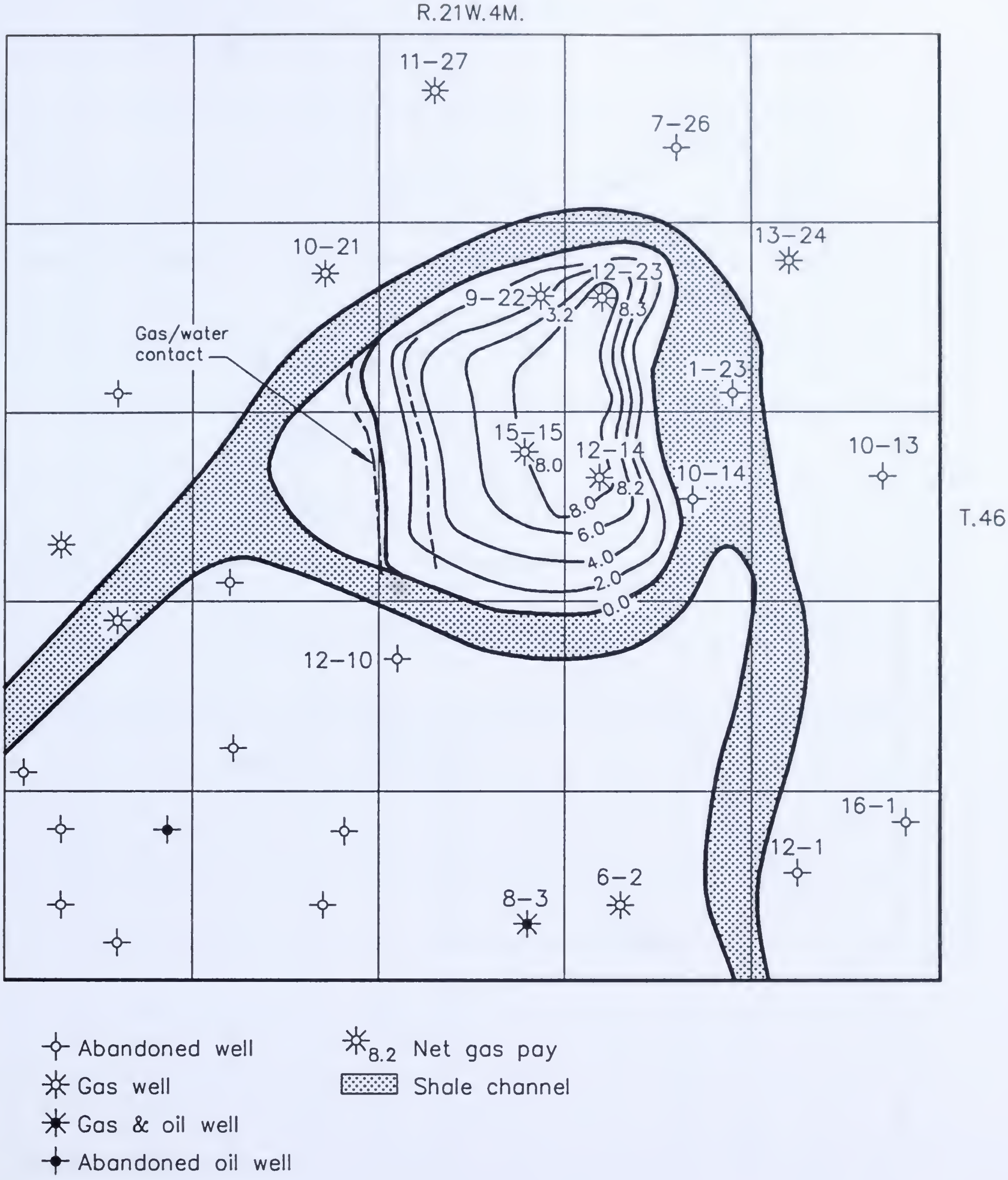

Figure 2 Northstar's Net Gas Pay – Ellerslie D Pool

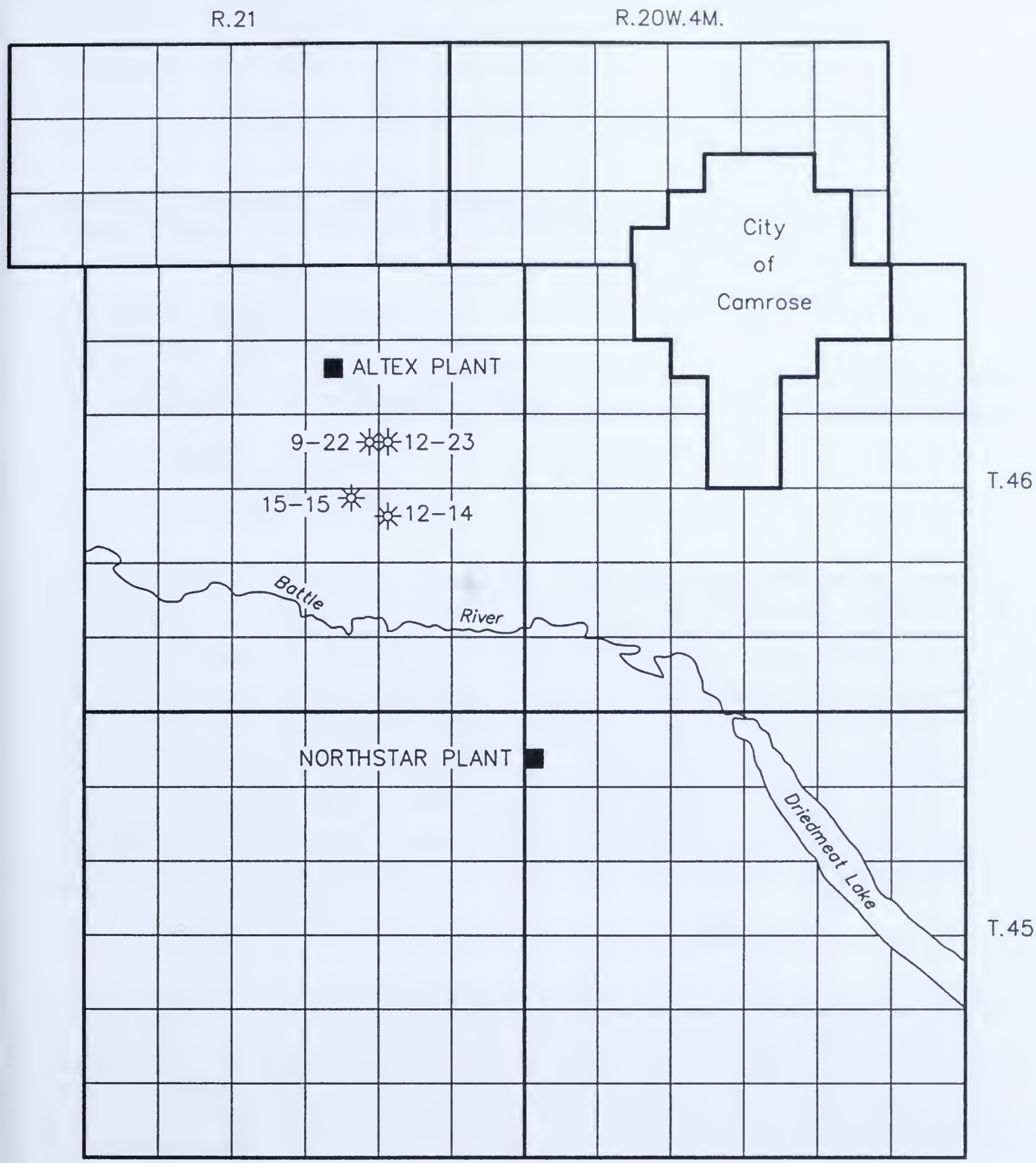

Figure 3 BITTERN LAKE AREA

ERCB

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

DAISHOWA CANADA CO. LTD.
PEACE RIVER PULP MILL
INDUSTRIAL DEVELOPMENT PERMIT
TO USE GAS AS A SUPPLEMENTARY FUEL

Decision D 90-7
Application 891642

1 INTRODUCTION

1.1 Application

Daishowa Canada Co. Ltd. (Daishowa), through its consultant Pacific Liaicon Ltd., applied on 27 October 1989, pursuant to section 30 of the Oil and Gas Conservation Act (the Act), to the Energy Resources Conservation Board (Board or ERCB) for an industrial development permit (IDP) authorizing the annual use of up to 80.2 million cubic metres (10^6 m^3) of natural gas, as supplementary fuel in the production of 340 air-dried kilotonnes per year (kt/yr) of bleached kraft pulp. The applicant requested a permit term of 20 years. The Daishowa Peace River pulp mill, located approximately 16 kilometres from the town of Peace River, was under construction at the time Daishowa filed its application with the Board. Section 30 of the Act requires that where an industrial plant in the Province will require more than 1 petajoule[1] per year (PJ/yr) of an energy resource for fuel and feedstock or more than 100 terajoules per year for feedstock only, the plant operator must obtain an IDP authorizing the use of the energy resource.

1.2 Hearing

A public hearing was opened on 3 April 1990, but was adjourned and rescheduled to 26 and 27 April 1990 in Peace River, Alberta. The Board panel members at the opening of the hearing were N. A. Strom, P.Eng., F. J. Mink, P.Eng., and E. J. Morin, P.Eng. The Board panel at the hearing proper consisted of N. A. Strom, P.Eng., Dr. J. P. Prince, Ph.D., and J. R. Nichol, P.Eng. (Acting Board Member). Those who appeared at the hearing are shown in the attached table.

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1 In energy volume terms, 1 PJ is approximately 26.7×10^6 m^3 of methane or 26.0×10^3 m^3 of crude oil; 100 TJ is approximately 2.67×10^6 m^3 of methane or 2.60×10^3 m^3 of crude oil.

Interventions expressing concerns or opposition to the application were initially received from:

- John Sheehan and the Peace River Environmental Society (also known as the Friends of the Peace),
- the Edmonton Chapter of the Friends of the North,
- Sandy Kulyna, a landowner with lands adjoining the Peace River downstream of Daishowa's mill and a resident of Manning, Alberta,
- the Peace Country Fish and Game Association,
- the Alberta Wilderness Association, and
- the Alberta Federation of Labour.

Alberta Natural Gas Company Ltd (ANG) filed a letter supporting the application.

At the opening of the hearing, Crystal Reese appeared and stated that in addition to representing Sandy Kulyna, she would be representing her father, Peter Reese, in a separate intervention.

When the hearing opened on 3 April 1990, John Sheehan and the Friends of the Peace, the Edmonton Friends of the North, Crystal Reese, and the Alberta Wilderness Association requested adjournment in order to allow more time to properly prepare and document their submissions. John Sheehan and the Friends of the Peace and the Edmonton Friends of the North preferred an indefinite postponement of the hearing until matters relating to the mill and its construction permits, which were under consideration by the courts, had been dealt with and the need for a federal environmental assessment of the Daishowa Peace River pulp mill had been determined. Failing that, they and Crystal Reese suggested that a 1-month postponement of the hearing would be a sufficient time to prepare. As well, it would allow time to resolve local intervener status and thereby determine manner and extent of participation.

The Board concluded that it would not be appropriate to defer the hearing indefinitely while awaiting the outcome of the identified court cases. However, it agreed that some limited additional time was warranted in order to provide the interveners a fair opportunity to prepare and fully participate in the hearing. As a result, the hearing was rescheduled to 26 April 1990.

2 BACKGROUND

2.1 Daishowa Project Energy Usage

Daishowa requested the ERCB to authorize the use of a base amount of 2.3 PJ/yr and a contingency amount of 0.5 PJ/yr of natural gas as supplemental fuel for the manufacture of 340 air-dried kt/yr of bleached kraft pulp.

The gas would be used as supplemental fuel at the mill for the generation of process steam, for heating buildings at the site and regeneration of chemicals used in the kraft process. The mill is expected to produce approximately 78 per cent of its own total energy requirements by burning wood wastes from the operation. Natural gas and purchased electricity would provide approximately 21 per cent and 1 per cent respectively of the total energy requirement of the mill.

In the manufacture of kraft pulp, wood waste is generated from two parts of the process. The first is in the debarking of logs received at the site. This produces a material called hog fuel. At Daishowa's mill, it is expected that the debarking operations will produce 100 kt/yr of hog fuel having an energy value of 2.0 PJ/yr. The hog fuel will be burned in the power boiler to produce high-pressure steam. The anticipated natural gas supplement for the power boiler is 1.11 PJ/yr and would be used for boiler start-up, for meeting short-term fluctuations in steam demand, and for meeting steam demand when insufficient hog fuel is available.

The second type of wood waste that is produced by the process is lignin. Raw wood chips are "cooked" in a chemical solution, called liquor, under heat and pressure to dissolve the lignin which binds the individual wood fibres together. The wood fibres which will be processed further to produce the final pulp product are separated from the spent cooking liquor which contains the lignin. The spent cooking liquor is concentrated by evaporation and then burned in the chemical recovery boiler to release 6.4 PJ/yr of energy for high-pressure steam generation and also to regenerate the cooking liquor chemicals, sodium hydroxide and sodium sulphide. Natural gas consumption in the chemical recovery boiler is expected to be 0.21 PJ/yr and would occur during start-up and shut-down of the boiler.

High-pressure steam produced by the power and chemical recovery boilers passes through a turbine and generator to produce 36.5 megawatts of electrical power for the mill, and medium- and low-pressure process steam used for heating and drying.

In the chemical regeneration process, sodium carbonate and sodium sulphide drain from the bottom of the chemical recovery boiler. Once this green liquor is filtered to remove impurities, it is mixed with lime to produce the active cooking chemicals, sodium hydroxide and sodium sulphide. This reaction also produces a calcium carbonate mud which must be fired in the lime kiln to remove water and to regenerate the lime. The lime kiln is expected to use 0.76 PJ/yr of natural gas for fuel.

The brown wood fibre that is produced in the cooking or delignification process is then bleached with chlorine and chlorine dioxide to produce white fibre. Process water is removed from the white fibre by screening to produce a mat of fibre. This mat is further dewatered initially by squeezing between pressure rollers and then by evaporation in a steam-heated dryer. The final dried fibre mat is then cut into sheets to be shipped as bales.

2.2 Interveners' Positions

With the exception of the Peace Country Fish and Game Association, interveners at the hearing expressed general opposition to the Daishowa Peace River pulp mill because of concerns relating to the lack of prior public scrutiny of Daishowa's project, concerns relating to air and water pollution from mill effluent, concerns relating to forest operations in the Daishowa Forest Management lease area, and general concerns relating to the long-term viability of Daishowa's mill. This section of the report provides an overview of the concerns raised by the interveners.

With respect to public scrutiny of Daishowa's project, the interveners were of the view that the mill should not be allowed to start up until hearings were held to allow public input into a full, detailed review of the environmental impact of all aspects of the pulp mill project, including the forest operations. Some of the interveners were engaged in legal action against the federal and provincial governments in an attempt to obtain a court ruling directing the governments to conduct such a review. These interveners, the Edmonton Friends of the North, the Alberta Wilderness Association, Peter Reese, and the Friends of the Peace, expressed the opinion that it would be improper for the ERCB to conduct a hearing into the energy-use aspects of the project until the outcome of the requested all-encompassing public review was known.

With respect to airborne emissions from the mill, the interveners were concerned that these could cause health problems for residents around the mill and that odours would reduce area residents' enjoyment of their land. A specific concern was raised about the emission of dioxins from Daishowa's proposed burning of chlorinated sludge in the power boiler. It was felt that with the numerous temperature inversions that occur in the Peace River valley, this practice could pose an unacceptable health risk.

With respect to the discharge of aqueous mill effluents into the Peace River, interveners expressed concerns about effects this might have on the river locally as well as regionally downstream from the mill. Concerns were that this pollution would detract from local recreational uses such as swimming, boating, and fishing. This would affect local residents' enjoyment of the river and would also affect the potential to develop and generate revenue from tourism on the river. Concerns were also expressed about the toxicity and persistence of organochlorines that could accumulate in the river sediments and the health effects of these contaminants on fish and on persons eating fish from the river.

In addition to the local concerns, the interveners were of the view that pollution entering the river from the mill would have detrimental effect on the total Peace-Athabasca-MacKenzie River system.

They noted that two bleached kraft pulp mills already discharge effluent to the Peace River and that detectable contamination of fish, invertebrates, and sediment from dioxins and furans has shown up. The interveners were concerned about the effect of organochlorine pollution on Wood Buffalo National Park and in the Peace-Athabasca delta, a major wildlife and waterfowl habitat and breeding ground.

As an alternative to discharging aqueous mill effluent into the river, the Alberta Wilderness Association requested that the ERCB direct and assist Daishowa to investigate the potential for disposal of gaseous and aqueous mill effluents to a deep, sealed underground formation such as the Peace River Arch Leduc Formation which exists in the area of the mill.

With respect to forest harvesting operations associated with Daishowa's mill, the interveners expressed concerns related to potential adverse impacts on both local and regional scales. Damage of the forest ecosystem by clear-cutting would limit area residents' traditional use of the forests for recreation. Also, clear-cutting could cause the water table level to rise, resulting in flooding and destruction of local forest stands and unsuccessful reforestation efforts.

Among the regional considerations, concern was expressed by the interveners that no assurance exists that harvesting of the boreal forest under the Daishowa Forest Management Agreement (FMA) will be done on a sustainable basis. Also, key wildlife and fisheries habitats within the Daishowa FMA boreal forest area have not been properly identified and evaluated. The interveners argued that impact on these resources should be determined before the Daishowa pulp mill operations are allowed to proceed.

Another potential regional effect identified by the interveners was that forest harvesting could affect the timing and intensity of surface runoffs, thereby changing the river flow regimes and possibly damaging wetland habitat at the Peace River delta. The interveners also expressed a concern that large areas of forest land, including land within Wood Buffalo National Park, were being placed in perpetuity under the control of a giant non-Canadian company.

Finally, interveners argued that, as designed, Daishowa's mill may not be economically viable for a long period of time. For example, increasing demand for recycled and unbleached paper products may significantly reduce the demand for raw pulp. Also, new federal and provincial guidelines aimed at zero discharge for pulp mills and the environmental consequences of the kraft process may make Daishowa's mill obsolete.

For the foregoing set of reasons a majority of the interveners suggested that there were both specific and broad reasons why it would be in the public interest to deny the application for the use of gas as a supplemental fuel.

The Peace Country Fish and Game Association stated that it supported the economic development that Daishowa's mill would bring to the region with the proviso that the project not jeopardize fish and wildlife habitats in the area.

The Peace Country Fish and Game Association was especially concerned that no co-ordinated communication process was yet in place that would enable interested parties such as itself to consult jointly with Daishowa and relevant government departments respecting the design and operation of the plant and woodland operations, and address specific concerns regarding fish and wildlife habitat protection.

2.3 ERCB Jurisdiction Under Section 30 of the Oil and Gas Conservation Act

The scope of the Board's jurisdiction as it relates to the application for an IDP was raised at the hearing. The Board's jurisdiction derives from a section of Part 7 of the Act entitled "Production and Use of Gas". Section 30 prohibits the use of an Alberta energy resource including gas, methane, ethane, propane, butanes, pentanes plus, condensate, or crude oil in amounts greater than 1 PJ/yr for fuel and feedstock or greater than 100 terajoules/yr for feedstock only, for any industrial or manufacturing operation unless the Board has granted a permit authorizing that use. As well, subsection 30(6) reads as follows:

> "The Board shall not grant a permit under this section unless in its opinion it is in the public interest to do so having regard to, among other considerations,
>
> (a) the efficient use without waste of the energy resource, and
>
> (b) the present and future availability of hydrocarbons in Alberta."

In its preliminary assessment of Daishowa's application for an IDP, the Board interpreted its responsibility under section 30 of the Act and decided that for non-energy industrial operations where hydrocarbon resources constitute only a small fraction of the energy requirements, the Board would limit its considerations to factors pertaining to the availability of the needed hydrocarbon resources, the efficient use thereof, and the environmental effects relating to emissions from their use.

That Board position was reflected in the nature of the additional information requested of the applicant to complete the application. It was also reflected in the Board's Notice of Hearing

issued on 5 March 1990 and in the Amended Notice of Hearing issued on 8 March 1990 which stated:

> "In accordance with its legislation, the Board will consider submissions related to the efficient use without waste of the gas to be used as supplementary fuel at the mill and the present and future availability of hydrocarbons in Alberta."

The foregoing notwithstanding, most interveners urged the Board to consider a broad spectrum of issues, including the potential environmental and health impacts of the mill on local and downstream areas, the appropriateness of current environmental standards as they are applied to pulp mill operations, the long-term economic viability of the mill, and the environmental impacts of the woodland operations associated with the mill.

The applicant, Daishowa, was of the view that the Board should consider issues relating only to the use of natural gas at the mill. In Daishowa's view it had already addressed and satisfied various government departments with respect to all of the other issues raised by the interveners through the process of obtaining the necessary permits and licences for the construction and operation of the mill and its associated woodland operations. This process included the preparation of an environmental impact assessment which was reviewed by the government departments that are responsible.

The Board carefully weighed the arguments put forth by both the interveners and the applicant respecting the scope of issues that it should consider in deciding whether or not approval of Daishowa's IDP application would be in the public interest.

The Board concluded that its initial position regarding the appropriate scope of the hearing was correct: the issues the Board must examine in assessing the public interest relate specifically to the use of gas at the mill. The scope of consideration should be confined to the availability and efficient use of the required hydrocarbon reserves and the incremental environmental effects arising from their use. In the case at hand we are dealing with a non-energy industrial operation where only a small fraction of total energy needs is from regulated hydrocarbon resources; where those hydrocarbon resources are supplemental fuel only; and where the overall operations would occur regardless of whether or not the Board approves the use of Alberta natural gas.

The wording of the Act clearly implies that the Board should focus primarily on the availability and use of resources regulated under the Act. In cases where the project is able to proceed with fuel from a non-regulated source, the Board believes that its jurisdiction, as defined by the Act, is limited to the effect on the public interest that is directly and solely attributable to the use of the regulated resource. In the case at hand, Daishowa submitted that operation of the mill would proceed even if the volume of Alberta natural gas applied for was not allowed. That submission was not challenged and is well supported by the evidence. So

the Board will limit its review to factors directly associated with the use of natural gas, including the potential incremental effect on the environment attributable to the use of gas as compared to other possible fuels.

3 USE OF NATURAL GAS AT THE DAISHOWA MILL

3.1 Applicant's Views

Daishowa proposed to use a base amount of natural gas having an energy value of 2.3 PJ/yr and possibly use an additional contingency amount of gas having an energy value of 0.5 PJ/yr. This can be compared with the mill's overall energy requirement of some 11 PJ/yr. The total maximum gas usage at the mill over the requested 20-year permit term would be 1440×10^6 m^3. Daishowa noted that this amount represented less than 0.1 per cent of provincial natural gas reserve additions forecast for that 20-year period by the ERCB. Gas would be delivered to the mill site by an existing pipeline owned and operated by Shell and ANG. Daishowa has arranged to obtain its gas supply from ANG.

Of the requested base amount of 2.3 PJ/yr, 1.11 PJ/yr would be used as supplemental fuel in the power boiler, 0.76 PJ/yr would be used as fuel in the lime kiln, 0.21 PJ/yr would be used as supplemental fuel in the chemical recovery boiler, and 0.21 PJ/yr would be used for building heating.

The contingency amount of 0.5 PJ/yr was requested because circumstances could occur that would result in less than the expected amount of energy being available from hog fuel and thus gas consumption would be higher than the expected 2.3 PJ/yr base amount. Other factors that could cause gas consumption to increase would be the need to produce a larger proportion of softwood pulp using purchased softwood chips, the emergence of satellite hardwood chipping operations, and above-average moisture levels in the hog fuel consumed in the power boiler. Daishowa also evaluated as supplemental energy for its mill hog fuel from external sources, coal, oil, propane, and electricity. It concluded that for a number of technical and economic reasons, natural gas would be much preferred.

The power boiler would use all of the 100 kt/yr of hog fuel produced at the mill as primary fuel. Natural gas would therefore be used as an auxiliary fuel for boiler start-up, to meet short-term fluctuations in steam demand and to supplement the fluctuations of the indigenous hog fuel supply. Hog fuel from external sites such as sawmills would not be economically competitive after accounting for the costs of transporting it to the site. Daishowa stated that it would review the possibility of using additional hog fuel from sawmills on an on-going basis.

The lime kiln will require 0.76 PJ/yr of natural gas to provide heat to convert the lime mud ($CaCO_3$), a by-product of the cooking chemicals regeneration process, to reburnt lime (CaO) for reuse. Natural gas would provide the total energy input for the lime kiln. Daishowa stated that coal or hog fuel could not be used in place of gas in the lime kiln because ash

from their combustion would concentrate in the chemical recovery process loop and would contaminate the reburnt lime and cooking liquor. Also, electricity was not considered to be a feasible replacement for gas for the lime kiln because it would not provide the necessary heat input characteristics.

The chemical recovery boiler is expected to use 0.21 PJ/yr of natural gas during boiler start-up. As with the lime kiln, the use of hog fuel or coal in the chemical recovery boiler is not feasible because of ash contamination in the recycled chemicals. Also, electricity would not be a suitable replacement for gas because it would not provide the necessary heat input characteristics for start-up of the recovery boiler.

Daishowa stated that, if necessary, either propane or fuel oil could be used in place of natural gas as a supplemental energy supply for the mill. Transportation of either fuel oil or propane to the mill site, however, would be more difficult than natural gas and Daishowa's economic analysis showed that both fuel oil and propane would be more expensive than natural gas. Coal would be the only energy form that would result in a lower purchased fuel cost than natural gas. However, in net economic terms, the additional capital cost of a coal handling and storage system at the mill would more than offset the advantage in the purchased fuel cost of coal over natural gas.

Daishowa also considered the environmental aspects of alternative fuels for the mill and concluded that natural gas was superior to all the alternatives considered. The use of fuel oil or coal would be expected to produce increased emissions of sulphur dioxide (SO_2) and nitrogen oxides (NO_x). The use of fuel oil, coal, or additional hog fuel would be expected to produce increased particulate emissions. At the same time, Daishowa acknowledged that the use of additional sawmill hog fuel at its plant would lead to reduced emissions at area sawmill beehive burners. The use of propane would be expected to result in emissions similar to the use of natural gas but Daishowa noted that there would be increased risk of spillage during transportation. Daishowa also noted that the use of electricity would result in reduced SO_2 and NO_x emissions at the mill site but would result in increased emissions at Alberta coal-fired thermal power generating stations.

3.2 Interveners' Views

None of the interveners at the hearing argued that there would be insufficient gas available in Alberta to meet the needs of Daishowa's project. Some interveners, however, expressed the view that fuelling a pulp mill with natural gas is not the best use of the resource. Some interveners also expressed the view that the natural gas which Daishowa proposes to use would have greater value to the province if it could be saved and sold in the future.

Some interveners held the view that the mill should be energy self-sufficient or even a net energy producer rather than a consumer of natural gas. These interveners urged the Board not to authorize Daishowa's requested contingency amount of gas so as to force Daishowa to

be as efficient as possible. These interveners also urged the Board to require Daishowa to utilize all available hog fuel from sawmills in the region whether or not it is within economic hauling distance on a competing fuel basis. Interveners generally agreed that, although consuming additional hog fuel at the mill would increase particulate emissions somewhat at the mill, it would reduce to a greater extent particulate emissions from beehive burners at sawmills in the area for a net environmental benefit. One intervener expressed a concern, however, that this practice would strip the biomass from areas around the sawmills. The interveners did not express concerns relating specifically to any environmental effects of burning gas at Daishowa's mill.

3.3 Board's Views

The Board believes that the issues relating to whether or not the use of gas at Daishowa's mill would be in the public interest are:

a) Is sufficient gas available in Alberta to supply the project over the requested permit term?

b) Does the project represent an efficient use for Alberta gas having regard for process considerations and alternative lower-value energy supplies that could be substituted?

c) Are there unacceptable environmental impacts associated with the use of gas by the project?

d) Does the project result in a net economic benefit to the province?

a) Gas Supply

With respect to the availability of Alberta gas to supply the project, the Board is of the view that Daishowa's proposed use of gas represents an extremely small portion of the volume of gas currently available for contracting. Additionally, the Board accepts Daishowa's evidence that the amount of gas that would be used by the mill represents an even smaller portion of the amount of gas reserves which the Board forecasts will likely be added to Alberta's reserves base over the requested 20-year permit term.

b) Alternative Energy Sources

According to Daishowa, the mill will achieve 78 per cent energy self-sufficiency by consuming wood wastes generated in the process. This degree of self-sufficiency could be somewhat lower, depending on the quantity and quality of hog fuel actually generated at the mill; hence Daishowa requested a contingency amount of gas of 0.5 PJ/yr. Alternatively, the amount of gas consumed by the mill could be reduced somewhat if additional hog fuel is used

to reduce the supplemental gas for the power boiler and through improvements in the efficiency of the operations.

The Board has reviewed the technical and environmental considerations of using gas as the supplemental energy supply for the mill and also the technical and environmental considerations of the alternative fuels considered by Daishowa. Overall, it is evident that gas is the most practical form of supplemental energy that could be used for most of the process energy requirements. The possibility of using hog fuel or coal in the lime kiln and/or the chemical recovery boiler also appears technically unsound. Fuel oil or propane could be used in place of gas to operate the lime kiln and the chemical recovery boiler. However, in view of the ample natural gas supplies expected over the permit term, such options can be set aside at this time because the necessity does not exist.

c) Incremental Environmental Effects from Gas

Among the alternative supplemental energy sources considered by Daishowa, gas would result in the fewest environmental effects. However, the use of hog fuel from area sawmills for the power boiler would possibly result in a net environmental benefit compared to disposal of this kind of wood waste in beehive burners. The Board believes that this source of supplemental fuel should therefore be given more thorough consideration to determine if the potential environmental advantages would be achievable.

d) Economic Benefits

With respect to the final item, that being whether or not the project will result in a net economic benefit to the province, the Board notes Daishowa submitted that the project is expected to generate a net economic benefit to the province of $92 million (present value in 1989 dollars). In view of this net economic benefit, and having regard for the advantages of gas, the Board concludes that it is in the public interest to grant the IDP authorizing the use of gas in the amounts requested. The Board accepts Daishowa's assessment of the economics of using gas and the relative comparisons with the other fuels considered, given the current energy price situation. The Board also notes Daishowa's commitment as part of its on-going strategy to maximize the plant's energy and to examine periodically the use of hog fuel sourced from regional sawmills or the use of coal for the power boiler. The Board regards these as matters that may be important to the economic benefit of the province in the longer term and therefore would expect to receive periodic updates on the merits of implementing such use and the steps taken to maximize energy efficiency.

4 DECISION

The Board concludes that there are ample gas supplies to satisfy the requirements as a supplemental fuel, that use of gas is environmentally optimum, and that maximum economic benefits will accrue from the use of gas. The Board is satisfied that it is in the public interest

to grant the application. Therefore, having regard for its responsibilities under the Act, the Board is prepared, with the approval of the Lieutenant Governor in Council, to grant the applied-for industrial development permit to Daishowa Canada Co. Ltd. The permit would be in the form shown in the attachment, and would be subject to the terms and conditions contained therein and to any terms and conditions imposed by the Lieutenant Governor in Council.

DATED at Calgary, Alberta, on 18 July 1990.

ENERGY RESOURCES CONSERVATION BOARD

N. A. Strom, P.Eng.
Vice Chairman

J. P. Prince, Ph.D.
Board Member

J. R. Nichol, P.Eng.
Acting Board Member

THOSE WHO APPEARED AT THE HEARING PROPER

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Daishowa Canada Co. Ltd. (Daishowa) G. F. Dixon	W. H. Malkinson (of Pacific Liaicon) W. G. Morgan P. G. Sagert, P.Eng. (of Cirrus Consultants) A. Orr, P.Eng. (of H. A. Simons Ltd.)
John Sheehan and the Peace River Environmental Society (Friends of the Peace) A. Boucher J. Sheehan	J. Sheehan
Edmonton Friends of the North R. Lawrence	R. Lawrence
Peace Country Fish and Game Association D. Norheim	D. Norheim
Sandy Kulyna S. Kulyna C. Reese	S. Kulyna C. Reese
Peter Reese P. Reese	P. Reese
Alberta Wilderness Association V. Pharis	V. Pharis
Energy Resources Conservation Board staff A. Broughton B. C. Hubbard, P.Eng. W. A. MacDonald, P.Eng.	

ATTACHMENT FORM OF PERMIT

IN THE MATTER of an industrial development permit to Daishowa Canada Co. Ltd. authorizing the use within Alberta of gas produced in Alberta for the production of bleached kraft pulp

INDUSTRIAL DEVELOPMENT PERMIT NO. IDP 90-4

WHEREAS Daishawa Canada Co. Ltd. has applied to the Energy Resources Conservation Board, pursuant to section 30 of the Oil and Gas Conservation Act, for an industrial development permit authorizing the use of natural gas produced in Alberta as a supplementary fuel in the production of bleached kraft pulp in Alberta; and

WHEREAS the Board is of the opinion that the granting of the applied-for permit is in the public interest, having regard to the efficient use without waste of natural gas and the present and future availability of natural gas in Alberta; and

WHEREAS the Lieutenant Governor in Council, by Order in Council, numbered _______ and dated _______________, has authorized the granting of the permit.

THEREFORE, the Energy Resources Conservation Board, pursuant to the provisions of section 30 of the Oil and Gas Conservation Act, being chapter 0-5 of the Revised Statutes of Alberta, 1980, hereby grants an industrial development permit to Daishawa Canada Co. Ltd. (hereinafter called "the Permittee") authorizing the use of natural gas as a supplementary fuel in the production of bleached kraft pulp, subject to the regulations and orders made pursuant to the said Act and to the terms and conditions prescribed in this permit as follows:

1. This permit is for the use by the Permittee of natural gas as a supplementary fuel in the production of not less than 340 air-dried kilotonnes of bleached kraft pulp per year at the level of gas use approved in clause (4), and generally as described in the application from the Permittee to the Board dated 27 October 1989.

2. The natural gas as supplementary fuel authorized by clause 1 is for use in a bleached kraft pulp mill which is located in Section 11, the North-west quarter of Section 12, the West half and North-east quarter of Section 13, the North-east quarter of Sections 14 and 56, Range 22, West of the 4th Meridian.

3. Subject to the conformity by the Permittee with the terms and conditions hereof, this permit shall be for a term commencing on the date hereof and ending on 31 December 2010.

4. The quantity of natural gas that may be used as supplementary fuel in the plant referred to herein in the production of bleached kraft pulp shall not exceed

(a) 80.2 million cubic metres per calendar year for the period ending 31 December 1991, and

(b) 74.9 million cubic metres per calendar year for the period 1 January 1992 to 31 December 2010.

5. The quantities of gas for the purpose of this permit shall be on the basis of a gas free of water vapour and having a higher heating value of 37.4 megajoules per cubic metre.

6. All gas used in producing bleached kraft pulp pursuant to this permit shall be measured by or on behalf of the Permittee in a manner satisfactory to the Board, and the volume produced shall be separately reported to the Board in a manner satisfactory to the Board.

7. The Permittee shall operate the plant in a manner that results in

(a) the maximum practicably and economically obtainable efficiency in the burning of gas as fuel in the production of bleached kraft pulp, and

(b) the maximum practical and economical conservation of gas which includes minimizing the use of gas by maximizing the use of hog fuel in the operation of the pulp mill.

8. The Permittee shall

(a) review the energy conservation aspects of the mill operations that relate to natural gas usage and report the results to the Board triennially, and

(b) review the use of other sources of energy including coal and sources of hog fuel external to that generated on the mill site and report the results to the Board every 5 years.

9. The Permittee shall not

(a) assign this permit, or

(b) release from its control the operation of the pulp mill,

without the consent in writing of the Board, which may, with the authorization of the Lieutenant Governor in Council, be given by the Board upon application therefor.

10. (1) Attached hereto as Appendix A and made part of this permit is the order of the Lieutenant Governor in Council authorizing the granting of this permit.

(2) This permit is subject to the terms and conditions, if any, prescribed by the order of the Lieutenant Governor in Council set out in Appendix A.

11. Where it appears to the Board or the Lieutenant Governor in Council that the Permittee has contravened or failed to comply with any terms or conditions contained in this permit or any relevant statutes or regulations of Alberta,

(a) the Board shall review the permit and with the approval of the Lieutenant Governor in Council may cancel the said permit or take such other remedial measures as considered suitable by the Board and the Lieutenant Governor in Council in the circumstances, or

(b) the Lieutenant Governor in Council may amend, vary, add to or replace any terms or conditions contained in this permit.

12. Notwithstanding the provisions hereof, the Permittee shall comply with the provisions of any Act, regulation, order or direction governing the drilling for, production, conservation, gathering, transportation, processing, purchasing, acquisition, sale, measurement, reporting, testing, supply or delivery of energy resources within the Province.

MADE at the City of Calgary, in the Province of Alberta, this __________ day of ______________________.

ENERGY RESOURCES CONSERVATION BOARD

ERCB D90-8
PROCEEDING 890971

ERCB

Caroline Beaverhill Lake Gas Development Applications

Shell Canada Limited
Husky Oil Operations Ltd.

August 1990

ERCB

Caroline Beaverhill Lake Gas Development Applications

Shell Canada Limited
Husky Oil Operations Ltd.

CAROLINE BEAVERHILL LAKE GAS DEVELOPMENT APPLICATIONS
ERCB D90-8

August 1990

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FIGURES AND TABLES

1 INTRODUCTION

1.1 Background

The Caroline Beaverhill Lake gas reservoir was discovered by Shell Canada Limited (Shell) in January of 1986. The reservoir is in the Swan Hills Member of the Beaverhill Lake Formation at a depth of close to 4000 metres (m). The reservoir contains an estimated 56 billion standard cubic metres (m^3) of gas which has an average hydrogen sulphide (H_2S) concentration of 35 per cent and also a high content of condensate and other natural gas liquids. Presently there are 18 wells drilled into the pool.

In late 1987, the reservoir owners, led by Shell, Gulf Canada Resources Limited (Gulf), and Canterra Energy Ltd. (subsequently Husky Oil Operations Ltd. (Husky)), joined together as the Caroline Area Gas Development Group (CAGDG) to prepare a co-ordinated development plan for the Caroline gas reserves.

In December 1988, CAGDG put forward a draft proposal called the Selected Development Option, under which about one-third of the Caroline gas would be pipelined northward to the existing Husky Ram River and Gulf Strachan gas plants, and the remainder would be processed at a new gas plant to be constructed near the Caroline field.

In March 1989, Husky advised CAGDG that it would no longer support the Selected Development Option because it believed the scheme would create greater environmental impacts, and was receiving public opposition. Subsequently, in July 1989, Shell applied on behalf of itself and all the Caroline working interest owners, except Husky, for approval to construct a new gas plant located near the field (Site E) to process all of the Caroline gas reserves. Shortly thereafter, Husky applied for approval to process all of the Caroline gas at its Ram River gas plant which it proposed to expand. Husky's proposal also included the construction of a gas transmission plant at Site E and gas transmission pipelines from Site E to Ram River.

During the latter part of 1989 and early 1990, Shell and Husky submitted additional documents to complete and support their respective applications.

Figure 1 shows the general area of the Caroline gas field, the location of some of the major facilities proposed by the applicants, and certain significant geographic features. The field is located in a farming, ranching and recreational-use area, close to the Green Area (provincial forest reserve).

During the formulation of the Selected Development Option, and subsequently the separate Shell and Husky proposals, the proponent companies communicated with the local public through numerous open houses, meetings, and mailings. This resulted in a number of local groups becoming involved, including the following:

- The Caroline Advisory Board (CAB) which was formed in January 1988 to represent municipalities and local residents in the project region.
- The Burnstick Lake Cottage Owners' Association (BLCOA) was in existence prior to the Caroline discovery, representing 57 cottage owners at Burnstick Lake, located some 6.5 kilometres (km) northwest of the proposed Shell and Husky gas plant location at Site E.
- The Preservation of Agriculture and Living Space Society (PALSS) which was formed in January 1989, representing residents and landowners largely in the Bearberry area west and northwest of the town of Sundre.

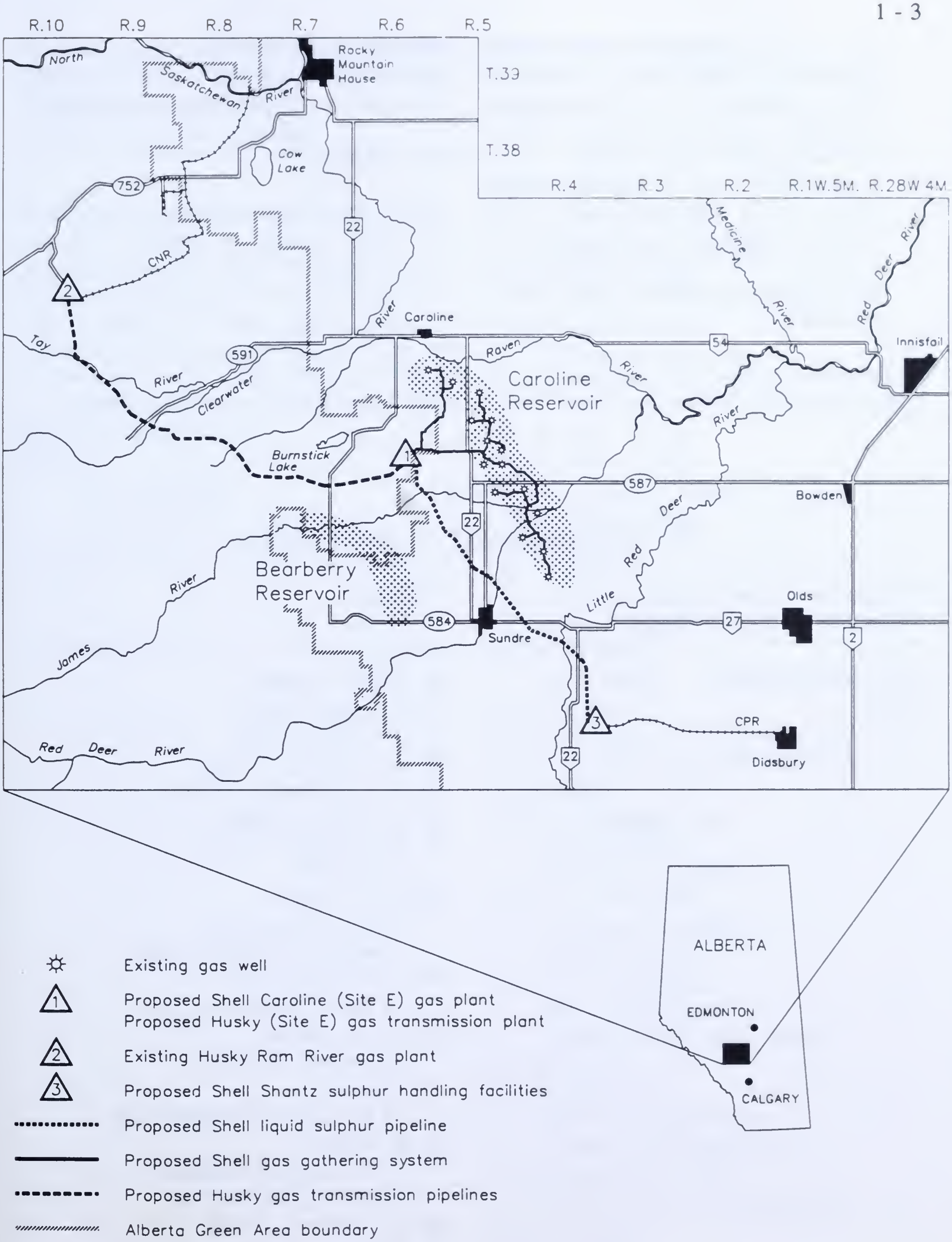

FIGURE 1 CAROLINE REGION

- The Concerned Residents Action Group (CRAG) which was formed in September 1989, representing 43 families in the immediate area of the Shell and Husky proposed gas plant sites (Site E).
- The Mountain View Land Holders Group which was in existence prior to the Caroline discovery, representing residents and landowners in the Eagle Valley area near the southern portion of the Caroline gas field.

A prehearing meeting was convened by the Energy Resources Conservation Board (the Board) in Caroline on 30 January 1990 to establish the date and location for the hearing of the Caroline development applications.

1.2 Hearing

The applications were considered by the Board at a public hearing in Caroline, Alberta, commencing on 17 April 1990 and continuing to 10 May 1990, with G.J. DeSorcy, P.Eng., F.J. Mink, P.Eng., and B.F. Bietz, Ph.D., sitting. Final argument was heard in Caroline on 28 and 29 May 1990. Those who participated at the hearing are listed in **Table 1**.

TABLE 1

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Shell Canada Limited (Shell) D. O. Sabey, Q.C. J. E. E. Lowe	R. Woods, P.Geoph. L. E. Auger, P.Eng. W. W. Evans, P.Eng. W. D. McQuitty, P.Eng. R. W. P. Symonds, P.Eng. W. S. Welling, P.Eng. R. M. Wrubleski, P.Eng. all of Shell Dr. F. G. Bercha of F.G. Bercha and Associates (Alberta) Limited Dr. T. L. Dabrowski of Piteau Engineering Ltd. Dr. D. M. Leahey of Western Research J. A. Lore of Jim Lore & Associates Ltd. D. B. Ramsay of Ramsay and Associates Consulting Services Ltd. W. M. Veldman, P.Eng. D. E. Reid both of Hardy BBT Limited

THOSE WHO APPEARED AT THE HEARING (cont.)

Principals and Representatives (Abbreviations Used in Report)	Witnesses
	D. A. Young of Environmental Management Associates A. B. Coady, P.Eng. of Delta Projects Inc. (Delta) W. B. Friedenberg of Brent Friedenberg Associates Ltd.
Husky Oil Operations Ltd. (Husky) A. L. McLarty R. A. Neufeld S. Purcell	A. R. Price, P.Eng. D. J. Ferris, P.Eng. J. D. Kingsbury, P.Eng. M. D. Little, P.Eng. R. Manning D. A. McCoy J. L. Milne, P.Eng. J. Uncles, P.Eng. B. W. Worbets all of Husky D. L. Dabbs M. J. E. Davies R. V. Portelli, P.Eng. J. A. Smith M. J. Zelensky, P.Eng. all of Concord Scientific Corporation Dr. D. A. Hackbarth of Stanley Associates Engineering Ltd. Dr. H. J. Ruitenbeek of H. J. Ruitenbeek Resource Consulting Limited H. G. Pearce D. W. Schwanbeck both of The Coopers & Lybrand Consulting Group P. K. Symborski, P.Eng. of Symborski & Associates Ltd. Dr. D. Maynard Dr. K. Mallett both of Forestry Canada

THOSE WHO APPEARED AT THE HEARING (cont.)

Principals and Representatives (Abbreviations Used in Report)	Witnesses
	A. Blair, P.Eng. M. Potter, P.Eng. R. Stothard all of Fluor Daniel Canada Inc.
Federated Pipe Lines Ltd. (Federated) A. S. Hollingworth	J. Sim M. J. Massecar, P.Eng. R. W. McKay, P.Eng. all of Home Oil Company Limited K. Gilmore of Tera Environmental
Amoco Canada Petroleum Company Ltd. (Amoco) V. J. Carson	D. English, P.Eng.
Altana Exploration Company (Altana) W. H. Schlieman	H. Heise, P.Eng.
ATCOR Ltd. (ATCOR) G. Chury	G. Chury
Canadian Hunter Exploration Ltd. (Canadian Hunter) J. Ballem, Q.C. R. Hansford	J. A. Dillabough, P.Eng.
Gulf Canada Resources Limited (Gulf) D. Gandar	D. Lovitt, P.Eng.
Mobil Oil Canada (Mobil) L. Anderson	L. Anderson
NOVA Corporation of Alberta (NOVA) H. D. Williamson	S. Senger

THOSE WHO APPEARED AT THE HEARING (cont.)

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Numac Oil & Gas Ltd. (Numac) J. H. Pletcher	J. H. Pletcher, P.Eng.
Union Pacific Resources Inc. (Union Pacific) J. Curran	B. Bowersock, P.Eng. N. Gundeson, P.Eng. T. Wiechart, P.Eng.
CN Rail (CN) J. J. Marshall, Q.C. M. Comeau C. Craig	J. Guppy, P.Eng.
CP Rail (CP) M. M. Szel P. Guthrie	M. Dugas
Alberta Fish and Game Association I. Johannson	I. Johannson
Pollution Sub-Committee of the Public Advisory Committees - Environment Council of Alberta P. Ramalingam	Dr. P. Ramalingam
J. Bauman L. Bauman	Dr. J. Bauman Dr. L. Bauman
R. and R. Brown and H. McCormick	R. Brown
J. and L. Brunner R. Heggie	J. Brunner L. Brunner
Burnstick Lake Cottage Owners' Association (BLCOA) J. Slavik W. L. McElhanney	D. Auld Dr. R. Rowe Dr. J. Whittaker

THOSE WHO APPEARED AT THE HEARING (cont.)

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Caroline Advisory Board (CAB) J. D. Rooke, Q.C.	R. Brown K. Guenther R. King J. Macklin K. Turnbull S. Vollmin
Caroline & District Chamber of Commerce R. Bancroft	R. Bancroft
Concerned Residents Action Group (CRAG) N. K. Machida	D. Brown J. Crozier P. Dahlman S. Johnston M. Taylor D. Willsie all members of CRAG Dr. B. Horejsi of OK Biological Services Ltd. B. Leach, P.Eng. of Golder Associates Ltd. N. McNally of McNally Land Services Ltd. L. Morasch, P.Eng. of Morasch Transportation Consultants Ltd. W. Roberts of the University of Alberta M. Thompson, P.Eng. of Nanuk Engineering Ltd. Dr. A. Younger of SKM Consulting Ltd.
County of Mountain View No. 17 S. Vollmin	S. Vollmin
Diamond J. Industries Ltd. J. Bandura	J. Bandura

THOSE WHO APPEARED AT THE HEARING (cont.)

Principals and Representatives (Abbreviations Used in Report)	Witnesses
D. and M. Harris	D. Harris
J. Hermann	J. Hermann
E. and B. Jans	E. and B. Jans
M. Kostuch and the Rocky Veterinary Clinic Ltd. (RVC) R. D. Schachter	Dr. M. Kostuch T. Bouman
J. and B. Macklin	J. Macklin
Mountain View Land Holders Group (Mountain View) M. Sihlis	M. Sihlis K. Jorsvick B. Macklin
Olds & District Chamber of Commerce J. Smith	J. Smith
Preservation of Agriculture and Living Space Society (PALSS) K. F. Miller G. T. H. Locke	A. Bakken T. Guzmanuk N. Stringer K. Walker all members of PALSS B. Parrott Dr. N. Zorkin both of Norecol Environmental Consultants Ltd. (Norecol)
Rocky Mountain House & District Chamber of Commerce P. Wasyk	P. Wasyk
L. and S. Roth	S. Roth
D. Saunders and 447 Area Residents D. Saunders	D. Saunders

THOSE WHO APPEARED AT THE HEARING (cont.)

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Sundre & District Chamber of Commerce D. Dewinetz	D. Dewinetz
Town of Innisfail P. Newman	P. Newman
Town of Rocky Mountain House T. Machan	T. Machan
Town of Sundre K. Guenther T. Leslie	K. Guenther
Village of Caroline D. Chapman	D. Chapman
R. E. Wolf	R. E. Wolf
Alberta Environment staff J. Lack, P.Eng. R. Stone C. S. Liu, P.Eng. B. MaGill K. Lowe S. Sakiyama, P.Eng.	
Energy Resources Conservation Board staff M. J. Bruni H. R. Keushnig, P.Eng. R. Creasey Dr. F. Rahnama T. Pesta, P.Eng. M. Semchuck D. Hubensky V. Makwich R. Palmer M. Pinney J. Wickens	

J. Dziadek appeared at the hearing and conducted cross-examination only, but did not present evidence or final argument.

The following filed interventions in support of Shell, but did not appear at the hearing:

DEKALB Energy Canada Ltd.
Home Oil Company Limited
Norcen Energy Resources Limited
PanCanadian Petroleum Limited
G. E. Allison Construction Ltd.
Sundre Emergency Medical Society
Sundre General Hospital
A. Macklin

The following filed interventions which did not support or oppose either applicant and did not appear at the hearing:

A. Ludwig
Municipal District of Clearwater No. 99

2 APPLICATIONS

2.1 Introduction

This section of the report summarizes the applications before the Board, and Section 3 summarizes the positions taken by the various interveners at the hearing. The information provided by participants was detailed and extensive, and is only briefly summarized in this report. The Board recognizes that its written summary may omit some matters considered important by others, but emphasizes that it has reviewed all of the evidence before it in reaching its conclusions.

2.2 Shell and Working Interest Owners

Shell submitted its applications on behalf of itself and, with the exception of Husky, all of the other working interest owners (Owners) of the Caroline Beaverhill Lake gas reserves as listed in **Table 2**. Together with Shell these Owners represent more than 88 per cent of the working interest of the Caroline Beaverhill Lake reserves.

Shell's proposal consisted of 14 individual applications filed by Shell and 3 associated applications which were filed by other applicants. A schematic map of the facilities is shown in **Figure 2** and the applications relating to Shell's project are listed in **Table 3**.

The Shell project would be comprised of the following four main components:

- the field gas gathering system consisting of 15 wells and 3 field compressor stations,
- a sour gas processing plant (Site E),
- a liquid sulphur pipeline system from Site E to Shantz, and
- sulphur forming and handling facilities at Shantz.

TABLE 2

WORKING INTEREST OWNERS
SHELL APPLICATION

Altana Exploration Company	(Altana)
ATCOR Ltd.	(ATCOR)
DEKALB Energy Canada Ltd.	(DEKALB)
Gulf Canada Resources Limited	(Gulf)
Home Oil Company Limited	(Home)
Mobil Oil Canada	(Mobil)
Norcen Energy Resources Limited	(Norcen)
Numac Oil and Gas Ltd.	(Numac)
PanCanadian Petroleum Limited	(PanCanadian)
Precambrian Shield Resources Limited	(Precambrian)
Scurry-Rainbow Oil Limited	(Scurry-Rainbow)
Shell Canada Limited	(Shell)
Esso Resources Canada Limited (Texaco Canada Resources)	(Esso)
Union Pacific Resources Inc.	(Union Pacific)

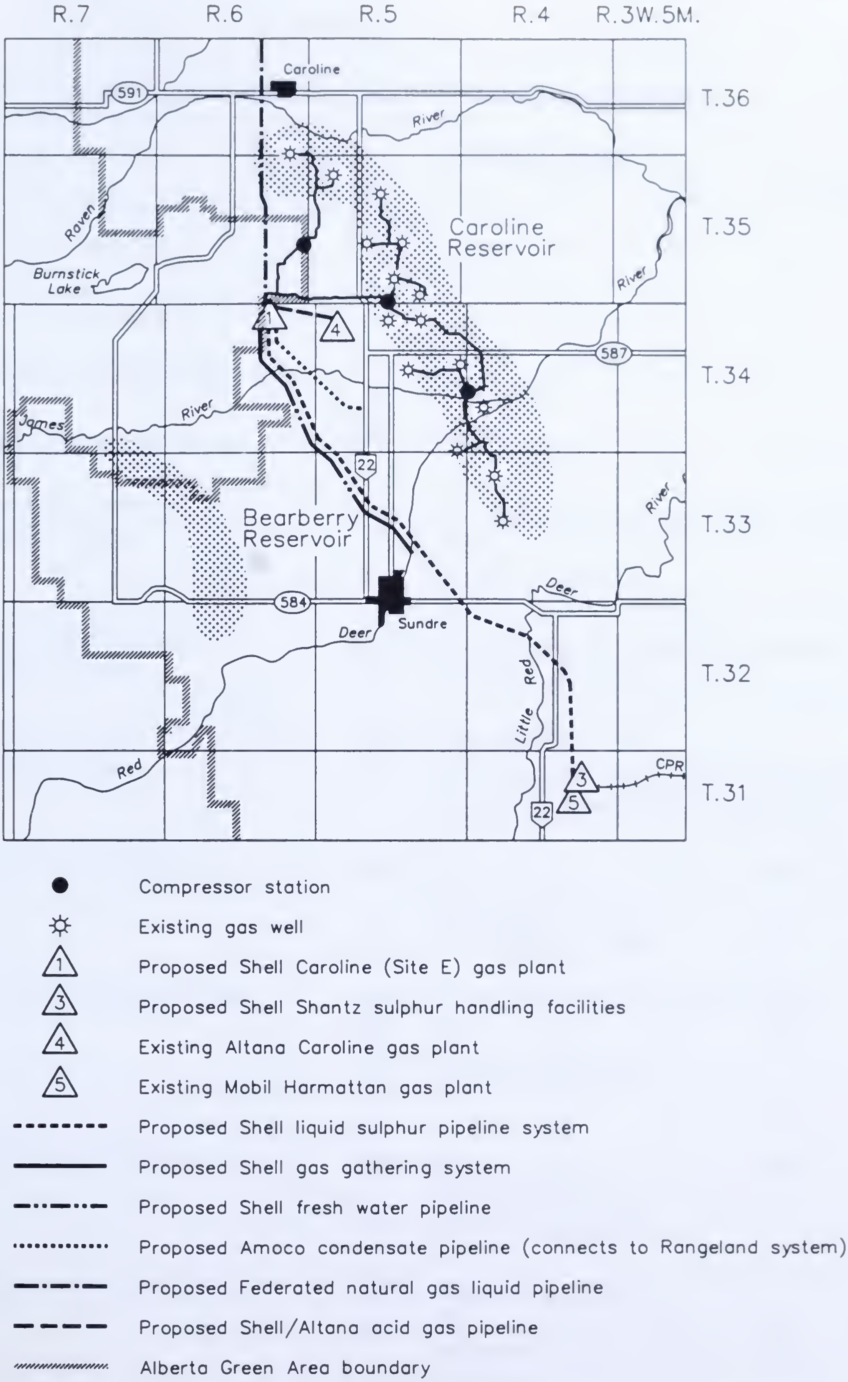

FIGURE 2 SHELL DEVELOPMENT PROPOSAL CAROLINE BEAVERHILL LAKE GAS RESERVOIR

TABLE 3

APPLICATIONS FOR SHELL'S PROPOSED DEVELOPMENT

Application Number	Facility		Facility Location Sec	Twp	Rge	Meridian
890969	gas plant (Site E)		34&35	34	6	W5
891504	North compressor station		13	35	6	W5
891505	Central compressor station		33	34	5	W5
891506	South compressor station		18	34	4	W5
891478	Sour gas gathering pipeline system	from:	15 producing wells in the Caroline field			
		to:	proposed gas plant			
891479	Sour liquids gathering pipeline system	from:	three proposed compressor stations			
		to:	proposed gas plant			
891480	Sweet fuel gas pipeline system	from:	proposed gas plant			
		to:	15 producing gas wells and other related facilities in the Caroline field			
891481	Fresh water pipeline	from:	19	34	5	W5
			(James River)			
		to:	proposed gas plant			
891482	Salt water pipeline system	from:	three proposed compressor stations			
		to:	30	34	4	W5
		from:	proposed gas plant			
		to:	29	34	5	W5
891568	Fresh water pipeline	from:	15	33	5	W5
			(Red Deer River)			
		to:	proposed gas plant			
891569	Sulphur product pipeline	from:	proposed gas plant			
		to:	35	31	4	W5
			(proposed Shantz sulphur forming facilities)			

TABLE 3

APPLICATIONS FOR SHELL'S PROPOSED DEVELOPMENT (cont.)

Application Number	Facility		Facility Location Sec	Twp	Rge	Meridian
891570	Sweet fuel gas pipeline	from:	proposed gas plant			
		to:	proposed Shantz sulphur forming facilities			
891571	Hot water pipeline	from:	proposed Shantz sulphur forming facilities			
		to:	proposed gas plant			
900404	Acid gas gathering pipeline	from:	36	34	6	W5
		to:	proposed gas plant			
891483[(1)]	Natural gas liquids pipeline	from:	proposed gas plant			
		to:	17	47	27	W4
891290[(2)]	Condensate pipeline	from:	proposed gas plant			
		to:	8	34	5	W5
900236[(3)]	Compressor addition		To be installed at Altana's gas plant at			
			36	34	6	W5

(1) Application submitted by Federated.
(2) Application submitted by Amoco.
(3) Application submitted by Altana.

2.2.1 Field Production Facilities

Wells

The Shell development would include the initial tie-in of 15 existing production wells. Ultimately, a total of 20 to 30 wells are anticipated to be tied in over the life of the field. Each well would have a subsurface safety valve (SSSV) installed near the top of the production tubing string, and would be designed to automatically shutoff flow from the well in the event of a surface facility failure or flow-line disruption. This valve would be tested regularly to ensure safe operation. Each wellhead would be equipped with two master valves for redundancy and a wing valve. In addition to the SSSV, each well site would have three other automatic control valves including the following:

- one emergency shutdown (ESD) valve at the wellhead,
- a second ESD valve installed downstream of the well-site heater, and
- a flow control valve (choke) installed between the coils in the well-site heater.

Like the SSSV, the ESD valves would be designed to close automatically in the event of abnormal conditions. A field control system would provide continuous monitoring of the field operating conditions to the proposed Shell gas plant control room. Alarms would alert the operators of any unusual situations and the safety valves could be activated remotely.

Gathering System and Field Compression

Raw[(1)] multi-phase (gas, oil, and water) production from each well would flow to one of three field compressor stations (South, Central, or North) where it would be separated into water, a single-phase sour[(1)] liquid stream and a single-phase sour gas stream. The produced water would be sent to a disposal facility for deep well injection. The single-phase sour liquids and the raw sour gas volumes would be piped in separate lines from the compressor stations to Shell's proposed Caroline gas processing plant at Site E.

Shell's gathering system would include 114.3-millimetre (mm) to 406.4-mm outside diameter (OD) pipelines, line block valves, pigging facilities (for cleaning the lines), a computerized Supervisory Control and Data Acquisition (SCADA) system, and a high-pressure sweet gas distribution system back to each well, field compressor, and other field facilities for lease fuel and purging. Shell applied to install a total of 72 automated line block valves, including those located at the compressor stations, at field pipeline junctions, and at its proposed plant, which would be situated at 31 locations in the gathering system. The compressor stations would be equipped with raw gas, raw liquid, and produced waterseparation facilities, a three-phase test separator, electric-drive compression for the raw gas volumes, liquid pumping equipment, produced water handling facilities, computerized SCADA system, emergency flare facilities, and related utilities.

The sour service pipelines would be designed to meet or exceed Level 3 requirements which are described in ERCB Interim Directive *ID 81-3*[(2)]. Shell incorporated a number of other design features to ensure greater safety, including:

- installing and operating the proposed compressor stations at the start of field production, which would allow the gathering pipelines upstream of the compressor stations to operate at pressures of 3500 to 4000 kilopascals (kPa) instead of at the wellhead pressure of 9000 kPa. The reduced pressure would significantly reduce the potential H_2S release volume in the event of a pipeline release;
- using a pipe-wall thickness at least twice that required by current regulations;
- installing a comprehensive leak detection and monitoring system. (This is further discussed in Section 9 of this report.)

Shell stated it had obtained pipeline easements from all the affected landowners and occupants for its proposed gathering system.

2.2.2 Gas Processing Plant (Site E)

Shell stated that its proposed Caroline gas plant would be designed to process a maximum of 9435 thousand cubic metres per day (10^3 m^3/d) of raw gas and gas equivalent of associated hydrocarbon liquids. At this design rate, Shell's total plant feedstock,

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(1) "Raw" means the unprocessed production and "sour" indicates that the streams would contain some H_2S and other sulphur compounds.

(2) ERCB Interim Directive *ID 81-3* Minimum Distance Requirements Separating New Sour Gas Facilities from Residential and Other Developments.

which would include Altana's acid gas, would which is equivalent to 4513 tonnes per day (t/d) of sulphur.

Shell stated that its proposed plant would be designed to meet the Board's current sulphur recovery requirement(3) which, for new plants with a maximum sulphur inlet rate of 2000 t/d or greater, is 99.8 per cent. Based on this minimum sulphur recovery efficiency, at design throughput rates, Shell's proposed plant would emit a maximum of 18 t/d of sulphur dioxide (SO_2) or 9 t/d sulphur equivalent to the atmosphere through an 85-m incinerator stack. Shell indicated that its expected annual average SO_2 emissions would be about 16.3 t/d or 8.1 t/d sulphur equivalent.

Shell's gas processing plant would consist of the following:

- inlet separation,
- condensate stabilization,
- compression (recycle and sales gas),
- gas sweetening (Sulfinol) for H_2S and carbon dioxide (CO_2) removal,
- dehydration,
- cryogenic natural gas liquids (NGL) recovery,
- Claus sulphur recovery units,
- Shell Claus Offgas Treating (SCOT) tail gas clean-up units,
- sulphur degassing and liquid sulphur pumping,
- NGL and stabilized condensate storage,
- waste water treatment, handling, and deep well disposal, and
- utilities and offsites.

All sour service components and processing facilities would be constructed in two equivalent parallel trains. (Plant design is discussed further in Section 6 of this report.)

2.2.3 Liquid Sulphur Pipeline System

Shell said it would use the Shell Sulphur Degasification Process at its Site E plant for degassing the produced sulphur. Entrained gas would be taken out of the liquid sulphur in sulphur degassing pits at Shell's proposed plant, reducing the H_2S content from 350 parts per million (ppm) to less than 10 ppm. At the request of area residents, Shell modified its gas plant application and eliminated the provision of an emergency sulphur block at the proposed Site E plant. There would be limited storage for approximately 8000 tonnes (t) of liquid sulphur which would be stored in above-ground covered storage tanks at the Site E plant. Provisions would be made to transport the liquid sulphur to Shantz by trucking in emergency situations.

The degassed liquid sulphur would normally be pumped directly 40 km from Shell's Site E gas plant to its proposed sulphur forming facilities at Shantz through an insulated 219.1-mm OD steel pipeline buried 1 m below ground. The temperature of the sulphur would be maintained at approximately 122 to 130 Celsius (°C) using pressurized hot water treated with corrosion inhibitors, pumped through an external 323.9-mm OD casing (jacket) surrounding the sulphur pipeline.

Three combined heater and water pumping stations would be required, one at Shell's proposed Site E plant and the other two at 14-km intervals along the pipeline. A 168.3-mm OD insulated hot water return pipeline would parallel the sulphur pipeline to permit circulation of the hot water.

The liquid sulphur pipeline would be designed to accommodate internal pipeline inspection

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(3) Energy Resources Conservation Board and Alberta Environment, August 1988. Sulphur Recovery Guidelines for Sour Gas Plants in Alberta, Informational Letter *IL 88-13*.

tools for corrosion monitoring. The whole pipeline would be encased in a water-tight polyethylene pipe to prevent external corrosion. Shell would utilize a SCADA system, integrated with the Site E gas plant control room to ensure safe operation and continuous control of the liquid sulphur pipeline system. Shell would install ESD valves at strategic locations on the line so that in the unlikely event of a leak, the portion of the disabled line could be closed to minimize the spill volume. Since the liquid sulphur pipeline would be enclosed by the hot water jacket, no sulphur would escape unless all the lines ruptured. Shell would also conduct regular visual inspections along the pipeline route. Shell stated that the liquid sulphur pipeline system, like the rest of its pipelines in the Caroline development, would have all critical systems designed for fail-safe operation[(4)].

Shell advised that it had acquired easements from all the affected landowners and occupants for its proposed liquid sulphur pipeline system.

2.2.4 Sulphur Forming and Handling Facilities

To accommodate the sulphur that would be produced at its proposed Site E gas plant, Shell applied to construct new sulphur forming, handling, storage, and loading facilities at Shantz in the southwest quarter of section 35, township 31, range 4, west of the 5th meridian (SW 1/4-35-31-4 W5M), which would be adjacent to Mobil's existing Harmattan sulphur recovery plant. The liquid sulphur would be formed into small spherical pellets at Shantz using the Sandvik Rotoforming process. Shell stated that it selected this process because it produces a product of low friability (ie. not easily crumbled), with a minimal sulphur dust created during forming, loading, and shipping.

Shell proposed to install storage facilities for 30 000 t of formed sulphur and 12 000 t of liquid sulphur storage capacity at Shantz. Shell added that only if there were extended disruptions to its normal sulphur shipping and marketing schedule would it pour sulphur to block at Shantz. Shell emphasized that it would not pour sulphur to block at its proposed Caroline gas plant at Site E.

A CP spur would be constructed from Mobil's existing facilities to Shell's sulphur forming, storage, and loading equipment. Shell stated it selected CP over CN because its route to Vancouver is 40 per cent shorter (1168 km versus 1624 km), and claimed this resulted in considerable cost and energy savings.

2.2.5 Hydrocarbon Product Pipelines

The Federated, Amoco, and NOVA product pipelines that would be required for Shell's development are described in Sections 2.4 and 2.5.

2.2.6 Altana Acid Gas

Shell applied to construct an acid gas pipeline that would transport acid gas from Altana's plant in 12-36-34-6 W5M (12-36) to Shell's proposed Caroline plant for sulphur recovery. Altana's plant is presently licensed to emit up to 5.9 t/d of SO_2 and currently flares all of its acid gas. By processing the acid gas and recovering the sulphur, Shell stated this would assist in improving the ambient air quality in the area by eliminating the Altana plant's current SO_2 emissions.

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(4) The facilities would be designed to automatically shutoff flow from a well or pipeline in the event of a wellhead or pipeline disruption.

Altana submitted a related application wherein it proposed to install a compressor at its 12-36 plant which is necessary to deliver the acid gas to Shell's proposed facilities.

2.2.7 Infrastructure

Roads

Shell planned to share in a program of road upgrading in the Caroline area with the MD of Clearwater No. 99 and Alberta Transportation. The upgrading program would include a 4.8-km paved extension west of Secondary Road (SR) 587 and a 14-km upgrade of the road from the Village of Caroline to its proposed Site E gas plant.

Electric Power

Shell estimated that approximately 20 megawatts (MW) of power would be required from TransAlta Utilities Corporation (TransAlta) for its proposed gas plant, sulphur pipeline system, and sulphur forming facilities. Another 32 MW would be required for the field facilities and gas gathering system. Shell stated that TransAlta would expand its power transmission system in the area to adequately meet these power requirements. Shell added that this upgrade should also benefit commercial and residential users in the general area by increasing electric power reliability.

Water Requirements

Shell estimated that its overall raw water requirements would average 100 cubic metres per hour (m^3/h). To reduce raw water demands, Shell proposed to re-use treated waste water. Water generated in the SCOT process, runoff water, and treated sewage would be used as additional water sources. Fresh water from a network of shallow wells in the Red Deer River valley would make up the remaining project water requirements.

Water Disposal

Shell stated that water produced from the reservoir would be separated from the raw gas and hydrocarbon liquids at the compressor stations and would subsequently be injected into a deep disposal well at 3-30-34-4 W5M. All liquid effluent collected at the proposed gas plant which could not be treated and re-used would be injected into a deep disposal well at 6-29-34-5 W5M. Shell emphasized that no produced water, sewage effluent, process fluids, or liquid wastes would be released to the watershed from Site E from the proposed plant site.

2.3 Husky

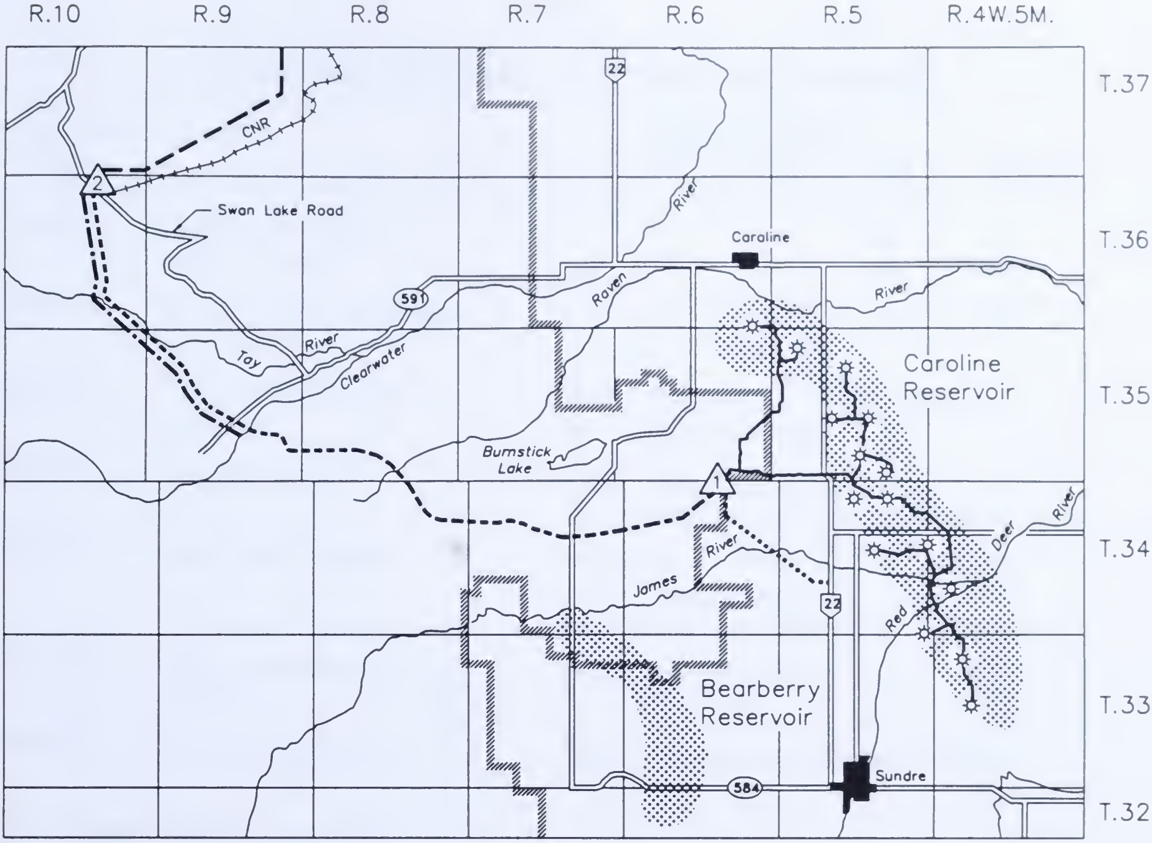
Husky submitted its applications on behalf of itself and its 100-per-cent-owned subsidiary, Canterra.

Husky's proposal is comprised of five individual applications filed by Husky and two associated applications which were filed by other applicants. The facilities relating to Husky's project are shown in **Figure 3** and the applications are listed in **Table 4**.

Husky's proposed facilities would be comprised of the following three main components:

- new Caroline gas transmission plant (Site E),
- sour gas transmission pipelines from Site E to Ram River, and
- an expanded Ram River gas plant.

Husky stated that it endorsed the Shell applications for the gas gathering and compression system which would be operated by Shell.



Existing gas well

Proposed Husky Caroline (Site E) gas transmission plant

Existing Husky Ram River gas plant

Proposed Husky gas transmission pipelines

Proposed Shell gas gathering system

Proposed Amoco condensate pipeline (connects to Rangeland system)

Proposed Husky fresh water pipeline

Proposed Federated natural gas liquid pipeline

Alberta Green Area boundary

FIGURE 3 HUSKY DEVELOPMENT PROPOSAL
CAROLINE BEAVERHILL LAKE GAS RESERVOIR

TABLE 4

APPLICATIONS FOR HUSKY'S PROPOSED DEVELOPMENT

Application Number	Facility		Facility Location Sec	Twp	Rge	Meridian
891047	Expansion of Ram River gas plant		35	36	10	W5
		and	2	37	10	W5
891757	Proposed gas transmission plant (Site E)		35	34	6	W5
891805	Sour gas transmission pipelines	from:	proposed gas transmission plant			
		to:	Ram River plant			
891804	Fuel gas pipeline	from:	Ram River plant			
		to:	proposed gas transmission plant			
891803	Fresh water pipeline	from:	15 (Clearwater River)	35	9	W5
		to:	Ram River plant			
891703(1)	Natural gas liquids pipeline	from:	Ram River plant			
		to:	17	47	27	W4
891802(2)	Condensate pipeline	from:	proposed gas transmission plant			
		to:	8	34	5	W5

(1) Application submitted by Federated.
(2) Application submitted by Amoco.

2.3.1 Field Production Facilities

Husky did not make separate application for any of the field production and gathering facilities and stated it endorsed the Shell applications for the entire gathering and compression system. Husky added that if its processing project were approved, Shell's field facilities and gathering proposal would be operated by Shell but would be fully incorporated into Husky's development.

2.3.2 Gas Transmission Plant (Site E)

Husky stated it would construct a gas transmission plant in the NW 1/4 35-34-6 W5M which is at the terminus of Shell's proposed Caroline field gathering system and would be at the same location as Shell's proposed Caroline gas plant. At the hearing, Husky stated it would be prepared to consider other possible plant sites.

Husky applied for a maximum daily raw gas inlet rate, including Altana's acid gas, of 8915 x 10^3 m^3/d. At its proposed design rates, Husky's total Site E plant feedstock would include a maximum of 3127 x 10^3 m^3/d of H_2S (4239 t/d of sulphur equivalent).

Husky stated that under normal operating conditions no SO_2 would be continuously emitted from its proposed Site E plant. However, as some sour gas would likely have

to be flared during plant upsets, Husky proposed to install a 78-m emergency flare stack to ensure air quality objectives and compliance with Alberta Environment's Clean Air Act. Sour vapours would be collected and sent to the stack where they would be combusted and converted to SO_2.

Husky stated that its proposed Caroline transmission plant would be somewhat unique in that it would process the Caroline inlet feed and would separate and treat the hydrocarbon liquids to produce saleable (stabilized) condensate. All of the sour gas would be compressed and transported by the proposed transmission pipelines to an expanded Ram River gas plant for final processing.

Husky's proposed gas transmission plant would utilize raw inlet separation, stabilization, overheads-gas compression, main sour gas compression, and condensate product storage and shipping facilities. At maximum daily throughput rates, the plant would process a maximum of 2926 m^3/d of stabilized condensate. The condensate would enter two 4400-m^3 storage tanks on the plant site from which it would be pipelined to Amoco's Sundre Terminal at 8-34-5 W5M and on through the existing Rangeland system to market.

Husky stated it would install three 3700-kilowatt (kW) electrically driven sour gas compressors at Site E in order to move the sour gas to its Ram River gas plant for further processing. Husky stated the compression system would operate with two compressor units on line with a third on stand-by.

2.3.3 Transmission Pipeline System

Husky's proposed transmission pipeline system would consist of two 406.4-mm OD single-phase sour gas pipelines, 55 km in length. The lines would extend from Husky's proposed gas transmission plant at Site E to the Ram River gas plant, and would be installed in separate trenches within a single pipeline corridor. Husky stated the lines would be designed to meet or exceed Level 4 requirements as described in ERCB Interim Directive *ID 81-3*. Husky also proposed to install an 88.9-mm OD sweet fuel gas pipeline from its Ram River plant. It would extend the full length of the transmission pipelines to provide a fuel gas supply for the proposed 25 automated line block valves and three line heaters on each transmission pipeline, and for the gas transmission plant at Site E. Husky also applied to construct a 168.3-mm OD fresh water pipeline from the Clearwater River at section 15-35-9 W5M to the Ram River plant to provide additional cooling water for the expanded gas plant. One 406.4-mm OD sour gas pipeline would share a common trench with the sweet fuel gas pipeline for the full length of the route and the second sour gas pipeline would share a common trench with the fresh water pipeline north of the Clearwater River.

Husky proposed to equip its dual sour gas transmission lines with cross-over piping at each end of the pipeline and at each line block valve location. Husky stated that its proposed dual sour gas pipeline system would

- reduce the potential H_2S release volumes in the event of a pipeline leak or rupture,
- allow the system to continue operating at a reduced capacity when any single line segment was shut down for maintenance or repairs, and
- allow the circulation of line pack volumes above the hydrate temperature during supply or delivery interruptions. This could assist in eliminating the need to purge or flare line pack during certain shut-down conditions at either end of the pipeline.

To further minimize public risk associated with the transmission pipelines, Husky would utilize a comprehensive leak detection system to ensure early detection.

In addition to the new fuel gas pipeline, Husky stated it would also have a sweet fuel gas tap and meter station from the NOVA sales pipeline which is near Husky's proposed gas trans-mission plant. Husky stated that in the event that its sour gas transmission pipelines would have to be purged and shut in, the NOVA tie-in would supply sufficient volumes of sweet natural gas to purge the entire sour gas trans-mission pipeline to the Ram River plant and thereby reduce the need to flare in the Carol-ine field or at the Site E transmission plant.

2.3.4 Ram River Gas Plant Expansion

The tabulation at the bottom of this page shows the Husky Ram River plant's currently approved rate and applied-for rate to accommodate the Caroline gas. Husky stated that its Ram River plant is currently processing raw feedstock from 14 fields. The inlet gas from the different fields, which varies in H_2S content from 10 to 34 per cent, is pipelined to Ram River through a gathering network of about 600 km which extends through a large segment of the foothills region.

Husky said that during normal operating conditions, it expected the plant's average daily SO_2 emissions to be 27.2 t/d (13.6 t/d sulphur equivalent). Husky indicated that because of its proposed higher sulphur recovery efficiency, the existing 91.4 m high incinerator at Ram River would be adequate to ensure compliance with Alberta Environment's Clean Air Act requirements.

Husky stated it would have to carry out a number of modifications at the existing plant in order to process the Caroline reserves, including the following:

- retrofit the sulphur recovery facilities to increase their sulphur recovery capacity by using oxygen-enrichment,
- remove the two Sulfreen units which handle the Ram River plant's present tail gas,
- modify the existing piping and equipment used in the plant's water treatment facilities,
- improve the plant's pneumatic systems by installing new instrument and plant air systems,
- improve and augment the fuel gas supply system,
- install new high- and low-pressure steam facilities and, if necessary, a new power boiler,
- expand the gas leak detection system,
- expand the fire detection and water system,
- modify the SCADA system, and
- upgrade the groundwater monitoring system.

	Current Approved Rate	Proposed Rate
maximum daily raw gas inlet (10^3 m^3/d)	17 749	26 244
maximum daily H_2S inlet (10^3 m^3/d)	3 437	5 014
(t/d sulphur equivalent)	(4 660)	(6 800)
annual average sulphur recovery efficiency (per cent)	98.4	99.8
minimum quarterly sulphur recovery efficiency (per cent)	98.1	99.5
maximum daily SO_2 emissions rate (t/d)	177.0	68.0

Husky said it would also have to install new facilities at its Ram River plant, including the following:

- inlet separation,
- gas sweetening (Sulfinol) for H_2S and CO_2 removal,
- a molecular sieve gas dehydration unit,
- propane refrigeration and cryogenic refrigeration provided by turbo-expansion (deep-cut) for ethane plus recovery,
- ethane plus product pressurized storage facilities,
- residue gas compression,
- a new oxygen (air separation) plant for oxygen-enrichment,
- two new SCOT tail gas clean-up units,
- new plant inlet and outlet ESD valves,
- a new plant emergency depressuring system,
- a new 78-m flare stack to handle the Caroline gas flaring requirements, and
- a cryogenic flare system.

2.3.5 Sulphur Forming and Handling Facilities

Declining production from existing fields has resulted in under-utilization of Husky's present sulphur handling facilities at Ram River. Husky indicated that even with the increased sulphur production from the Caroline reserves, the combined sulphur production would not exceed the Ram River plant's existing design sulphur handling capacity of 7800 t/d. Husky maintained that no modifications or expansion would be required to its existing sulphur handling facilities.

Husky did indicate that it would have to upgrade its sulphur degassing facilities which currently degas the sulphur down to about 40 ppm of H_2S. With its proposed modifications, Husky said that the modified sulphur degassing system would ensure the sulphur was degassed to below 12 ppm.

Husky acknowledged that excessive sulphur dusting is presently occurring at Ram River which it said is primarily due to the design and operation of its sulphur priller. It stated that if its Caroline development proposal were approved, Husky would modify its sulphur forming facilities to ensure that sulphur dusting at Ram River would not increase above present levels. It indicated that even if its Caroline proposal were not approved it would still proceed with a sulphur dust abatement program. It is currently evaluating various mitigative measures and plans to develop a solution to the sulphur dusting problem before the end of 1990. Husky said it would investigate various options including possible introduction of new sulphur forming facilities, such as the Sandvik Rotoforming Process or others, to replace the priller.

Currently the sulphur product from Ram River is shipped in different forms, some as molten sulphur in tankers, some slated, and the balance prilled. To help minimize sulphur dust, Husky had reduced the volume of sulphur being prilled. Husky said that after the appropriate remedial measures are incorporated, it should be able to increase the priller throughput without creating incremental sulphur dust. (The matter of sulphur dust at Ram River is discussed further in Section 8.7).

Husky indicated that it was in the process of remelting the remaining portions of the existing sulphur block at Ram River. If proposed Caroline sulphur has to be poured to block, Husky would use a portion of the existing block. It added that it would take appropriate steps including designing a new base pad for future sulphur storage which would prevent any further groundwater contamination. (The matter of sulphur storage and groundwater contamination is discussed further in Section 8.4).

2.3.6 Hydrocarbon Product Pipelines

The Federated, Amoco, and NOVA product pipelines that would be required for Husky's project are described in Sections 2.4 and 2.5 of this report.

2.3.7 Altana Acid Gas

Husky indicated it had held discussions with Altana and an understanding was reached that if Husky's proposal were approved, appropriate applications for the necessary facilities would subsequently be filed so that Altana's currently flared acid gas would be processed at Husky's Ram River gas plant.

2.3.8 Infrastructure

Roads

Husky's proposed upgrading of roads in the Caroline field and specifically in the vicinity of its proposed Site E gas transmission plant would be similar to that planned by Shell except for Husky's additional upgrade of the Swan Lake road which would improve the south access road to the Ram River plant. Husky stated the improved access would help accommodate increased traffic to the Ram River plant during construction and allow easier access to the plant from the Sundre and Caroline areas.

Electric Power

Husky said that electrically driven compression units would be utilized at its Site E gas transmission plant. Husky added that the estimated 8.1 MW of power for the plant would be supplied by TransAlta in the same manner as it would for Shell's proposed plant.

Husky stated that an expanded Ram River plant, to accommodate the Caroline reserves, would require additional power. Husky estimated that an additional 5 MW of electric power would be required for the expanded processing facilities and 21 MW for its proposed oxygen plant. TransAlta would have to upgrade its current supply lines to Ram River along existing rights of way (ROW).

Water Requirements

Husky said that 0.5 m^3/h of water would be required at its proposed gas transmission plant for domestic, utility, and fire control use. This would be obtained from water wells it planned to drill in the area.

The expanded Ram River plant would require an upgraded cooling water system and an associated evaporative cooling water tower. Husky estimated that its maximum water requirements at Ram River would be 300 m^3/h, with half of this provided by water produced from the proposed SCOT units. To meet the peak demands, the remaining 150 m^3/h would be pipelined from water wells which Husky would locate in the flood plain of the Clearwater River, near the crossing of its proposed transmission pipelines.

Water Disposal

Husky said that any formation water produced from the Caroline reservoir would normally be removed at Shell's proposed field compressor stations. If there was produced water in the raw inlet streams at its proposed gas transmission plant, it would install a pressurized sour water collection system and sour water stripper at the plant. The produced water would be transported either by truck, or if volumes warranted, by pipeline to a disposal well in the area for deep well injection.

Husky stated it would construct a surface water retention pond at its proposed gas transmission plant site. It said the pond design would include a leak detection system to

minimize the potential for groundwater contamination. Husky indicated that it would not have to construct new runoff or water treatment ponds at Ram River as the existing ponds could accommodate the expanded plant. Condensed water from the SCOT units would be used as cooling tower water make-up.

Husky did not plan to expand its existing water disposal system at Ram River. Process and other waste water is presently injected into two disposal wells in the area and a third well near the plant is available if needed. Sewage from the expanded plant and administrative buildings would be handled through the existing septic fields. Husky plans to continue treating and releasing surface runoff water to the surrounding watershed with a total water disposal rate of 38.5 m^3/h for the expanded plant. (Surface water is discussed in further detail in Section 8.3 of this report.)

2.4 Other Related Applications

2.4.1 Federated

Federated applied to construct a 219.1-mm OD NGL pipeline from either Shell's proposed Caroline gas plant or from Husky's Ram River plant to its existing pipeline system at 12-17-47-27 W4M at a point near the Esso Bonnie Glen gas plant as shown in **Figure 4**. The Federated pipeline system would deliver the NGLs to storage and processing facilities located in the vicinity of Fort Saskatchewan or to various miscible-flood (oil recovery enhancement) projects. The Federated pipeline associated with the Shell project would be approximately 158 km in length while the one associated with the Husky project would be approximately 160 km in length. Of the total length, the northern portion of some 100 km is common to both projects. Both projects would require a pump station at the start of the pipeline and at the interconnection with the existing pipeline system. All landowners and occupants for both of the proposed Federated pipelines have given their approval to the proposed pipeline routes and confirmed that they have no objection to the Board issuing a permit to construct a pipeline. Federated said that each of its pipeline proposals is feasible, safe, and environmentally sound and that either could be constructed at approximately the same cost.

2.4.2 Amoco

Amoco applied to construct a 168.3-mm OD condensate pipeline from Site E to its existing Sundre Pipeline Terminal in 16-8-34-5 W5M (as shown in **Figures 2 and 3**). Except for a minor difference in the starting point within Site E, the pipeline would be identical for both projects and would be approximately 9 km long.

2.5 Related Future Applications

2.5.1 NOVA – Associated with Shell Project

NOVA meter station facilities would be required to accommodate the fuel gas needs during the construction phase and subsequently the sales gas production. Since Shell's proposed Caroline gas plant would be situated immediately adjacent to NOVA's gas transmission pipelines, only a very short sales lateral would be required.

2.5.2 NOVA – Associated with Husky Project

To accommodate the increased sales gas production from the expanded Ram River plant, NOVA's existing meter station serving the plant would have to be expanded. Approximately 16 km of 660-mm OD pipeline would need to be constructed immediately adjacent to NOVA's existing pipeline, from the Ram River plant to NOVA's existing gas transmission pipeline.

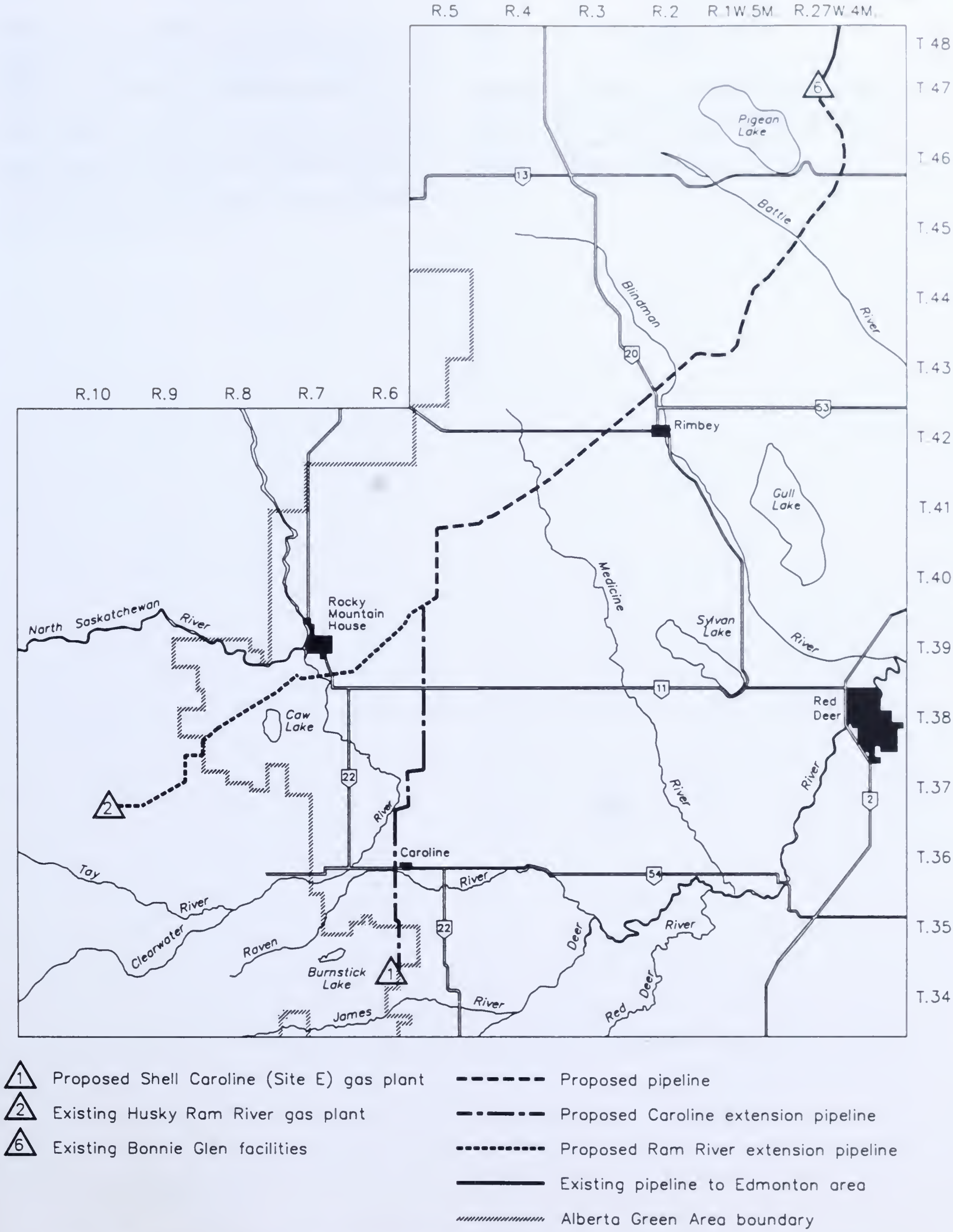


FIGURE 4 FEDERATED APPLICATIONS NATURAL GAS LIQUIDS PIPELINE

Without the Caroline gas, construction of a pipeline would be required although a 508-mm OD pipeline would be adequate. The Husky project would also require a NOVA meter station near Site E to provide fuel gas to purge Husky's proposed transmission pipeline to Ram River in the event of an emergency plant shut-down at Site E.

2.5.3 TransAlta

TransAlta would be required to submit applications for facilities to provide necessary electrical power for either project. (This matter is further discussed in Section 13.3.)

3 POSITIONS OF THE INTERVENERS

This section summarizes the position taken by various interveners respecting the Shell and Husky applications outlined in Section 2.

3.1 Altana

The Shell project includes a plan to have the acid gas from Altana's existing 12-36 gas plant moved to the proposed Shell plant for sulphur recovery.

Altana supported Shell's project because of its more favourable economics and Altana's strong preference for being an owner in a state-of-the-art gas plant. Altana expressed confidence in Shell's ability to operate the proposed plant and field facilities in an environmentally safe manner.

3.2 ATCOR

ATCOR appeared at the hearing in support of Shell but did not present direct evidence or final argument.

3.3 Gulf

Gulf appeared at the hearing to support Shell's development. Gulf stated it owns a 9.1 per cent interest in the Caroline gas reserves with a 2.4 per cent gross overriding royalty interest. Gulf said it performed a detailed economic assessment of both proposals and based on this evaluation it found Shell's project to be more economically favourable. Gulf also stated that Shell's proposal was the preferred option from the standpoint of co-ordinated area development, timing of that development, environmental and economic impacts, operator commitment, experience, and public health and safety.

3.4 Mobil

Mobil said it owns 2.5 per cent of the Caroline gas reserves and argued that the Owners' position is important and deserves to be weighed appropriately. Mobil stated it took a proactive approach in assessing both projects since it is an owner in the Caroline reservoir and in the Ram River gas plant, and also owns a 42.5 per cent interest in the Bearberry reservoir. After evaluating both proposals, Mobil concluded that Shell's project, which would have one operator for the plant and field, would be the optimum approach. Additionally, Mobil suggested that Bearberry would become commercial, and integration with Caroline would ensure more orderly development under Shell's proposal.

3.5 Numac

Numac indicated at the hearing that it owns a 2.6 per cent interest in the Caroline gas reservoir. Numac stated that following its examination of both proposals and recognizing that Shell would be utilizing state-of-the-art technology, it concluded that Shell's project was the safest, most reliable and efficient method of producing and processing the Caroline reserves.

3.6 Union Pacific

Union Pacific stated it owns a 6.72 per cent interest in the Caroline reserves and stressed that the position of the Owners must be given appropriate consideration by the Board. Union Pacific stated that it supported the Shell project for the following reasons:

- the proposal is technically superior and safer,
- it is specifically designed to process Caroline fluids,

- Shell is further ahead from an engineering standpoint,
- having one operator for the field and plant assures more orderly development,
- Shell is the largest Owner in the field,
- Bearberry synergy is designed into Shell's proposal,
- Shell has the support of all Owners, with one exception,
- Shell's proposal is economically superior,
- cost overruns would be less likely because Shell's project does not require integration of an old plant with a new one,
- Shell's proposal would give priority to Caroline gas,
- the new sulphur forming facilities would minimize sulphur dust,
- Shell's rail route to Vancouver is shorter, and
- Caroline Owners would not be exposed to the environmental liabilities that currently exist at Husky's Ram River plant.

3.7 Mountain View Land Holders Group

Mountain View appeared at the hearing and supported Shell's proposal. The group stated that since the local people would incur the risks arising from the wells and gathering system portion of the Caroline development, they should receive as much economic benefit as possible. They claimed Shell's project would provide more benefits which would include

- an increased tax base,
- more construction jobs,
- more permanent jobs,
- greater spinoff benefits, and
- more acceptable safety features.

The group made the following recommendations:

1. Scheduling of the trains hauling sulphur and worker shift changes should be established so that they do not coincide with school bus times.
2. The operator should pursue a program to advise high school students about work opportunities arising from the project and the training required to qualify for those jobs.

3.8 D. Saunders and 447 Area Residents

Mr. D. Saunders appeared at the hearing on behalf of himself and 447 Sundre and area residents who signed individual letters in support of Shell. They indicated in their letters that since they would be in the vicinity of the field facilities, and would be exposed to any potential risks, the economic benefits should also stay in the area. They also expressed a view that employment benefits and safety would be better ensured by Shell's proposal.

3.9 R. and R. Brown and H. McCormick

These three Caroline area residents and landowners, who were represented at the hearing by Mrs. R. Brown, supported the Shell proposal for the following reasons:

- the new technology and new equipment proposed by Shell would be better,
- the benefits from Shell's project would remain in the area of greatest risks, and
- the improved roads, as proposed by Shell, would reduce possible traffic hazards.

These residents said the support for Shell from Owners should also be given consideration.

They opposed Husky's proposal as it would interface new and existing equipment which would increase the potential for failure.

3.10 J. and B. Macklin

The Macklins, who live in the NE 1/4-17-33-4 W5M, indicated they would be affected by the Caroline sour gas development. They stated that Shell's proposal is best suited for the Caroline production for the following reasons:

- the plant would use the best up-to-date technology,
- shorter pipelines would minimize risk and disturbance to area residents,
- Altana's currently flared acid gas would be processed at Shell's Caroline plant where the sulphur would be recovered; therefore air quality around the Altana plant would improve,
- production from the Bearberry reservoir could be better accommodated at Shell's Caroline plant, thereby eliminating the need for an additional plant in the area, and
- Shell's proposal would create greater economic benefits which are required to offset long-term adverse effects associated with the field development.

The Macklins added that Shell, which discovered the reservoir and which has 89 per cent of the Owners' support, has always been sympathetic to the community needs and concerns.

Mr. Macklin said that during his more than 20-year association with oil and gas developments, neither he nor his family have experienced adverse effects to their health or to the health of their livestock. He believed that there would be no adverse effects on the agricultural community from Shell's proposal.

3.11 S. and L. Roth

The Roths, who live in the Eagle Valley area in the NW 1/4-33-33-4 W5M, supported Shell. They believe that a new gas plant using the latest technology is better than upgrading an older plant. The Roths said that Shell has a genuine concern for the safety and comfort of the local residents and it has made a real effort to keep residents regularly informed.

3.12 Village of Caroline

The Village of Caroline, which has a population of 387, is the closest community to the proposed Shell plant site. Mayor Chapman, who spoke on behalf of the Village, said his community would be directly affected by the proposed development. He stated that the community had thoroughly reviewed the Shell project and the Village strongly supported the Shell project for the following reasons:

- new technology is safer than mixing new and existing facilities,
- a new gas plant is safer and preferable to a long-distance pipeline transporting sour gas,
- Shell's project would distribute the benefits more fairly throughout the affected area communities, and
- Shell's gas plant design would ensure effective environmental performance.

The Village indicated that sulphur recovery at Husky's Ram River plant could be increased independently of the Caroline project.

3.13 Caroline Advisory Board

CAB, which is a municipally created committee, stated it was concerned with the Caroline gas field development and it endeavoured to provide public input into the development planning. CAB indicated it tried to remain neutral and communicated the relative advantages and disadvantages of both projects to the public. CAB said that it represented the majority of the local residents affected by the Caroline development and stressed that it spoke for the "silent majority". CAB stated that the success of its members in

the last municipal elections, and the lack of opposition for the re-appointment of the citizens at large who are active members, indicated that CAB enjoys the confidence of the majority of the local voters.

CAB stated that its fundamental principles in assessing the Caroline development proposals, in order of importance, were

- maintenance and commitment to maximum public health and safety, which includes impact on the environment,
- enhancement of local economic benefits, and
- co-ordinated development in the best interest of Caroline area communities, local residents, and resource companies.

With respect to public safety, CAB contended that the possible risks associated with various facilities in the project are in the following order of importance starting with the highest risk: wells, sour pipelines, compressors, plants, and product pipelines. CAB opposed lengthy sour gas transmission pipelines from the outset.

CAB stated that benefits must accrue to the people in the areas which bear the risks, but not at a cost to the environment. It added that the Shell project would provide more offsetting economic benefits to compensate for the risks and negative impacts of the field and gathering system. Those economic benefits would also be more fairly distributed throughout the region by Shell's proposal. Shell's use of best available technology would provide a more reliable and less environmentally damaging processing alternative. CAB stated that Shell's proposal best complies with CAB's fundamental principles and that it would be in the public interest to approve the Shell project.

CAB opposed the Husky project stating that the risk associated with the sour gas transmission pipelines is not necessary.

CAB said that the communities have been well informed about the projects and to ensure this would continue, CAB offered to participate in an overall umbrella group which could work in a co-ordinated approach with the successful applicant to help ensure that the project was implemented in an appropriate manner.

CAB recommended that any approval for the Caroline development should be subject to the following conditions:

1. Continue public involvement in implementation and operation of the project.
2. Provide for public input into the draft Emergency Procedures Manual.
3. Ensure that there are as many benefits as close to the field and gathering system as possible.
4. Assist the local communities in ensuring that proper community health and social service infrastructure is in place to accommodate the construction phase of the project.
5. Perform and continue all baseline studies.

CAB expressed support for the conditions recommended by RVC which would require a plan for evaluating social and environmental impacts of the project and comparing them to those discussed in the Environmental Impact Assessment (EIA) and Socio-Economic Impact Assessment (SEIA). It also supported the PALSS recommendations for conditions dealing with baseline studies and monitoring. CAB recommended that all monitoring results, remedial programs, plans, data, and comparisons should be filed with the ERCB and Alberta Environment and be made available to the public on request.

Should the Husky project be approved, CAB recommended the following further conditions, subject to consideration of the associated capital and operating costs:

1. Greater redundancy in the fractionating train at Husky's proposed Caroline gas transmission plant.
2. Shorter sour gas transmission pipeline sections utilizing the best block valve technology.
3. Rotoform sulphur forming facilities for all the sulphur recovered at Husky's Ram River gas plant.

Additionally, CAB supported the conditions proposed by RVC requiring the remediation of the groundwater and sulphur dust problems at Husky's Ram River plant site.

3.14 Town of Innisfail

Mayor Newman appeared on behalf of the Town and indicated support for Shell. She stated that Shell had made a good effort in keeping the community informed of its project. Mayor Newman said Shell's project would bring a greater positive socio-economic impact to the communities surrounding the Caroline field.

3.15 Town of Sundre

The Town, which is a community of 1789 persons, was represented by Mr. K. Guenther. The Town had requested each company to address the matters of economic, environmental, and social impacts on the community. After reviewing the respective responses, the Town Council unanimously voted in support of Shell's project. The Town Council advertised its position and believes that the lack of opposition to its decision was also indicative of the positive support of the community for the Shell project. Mr. Guenther said that the convoy, held in Sundre in May 1989, brought to light the extent and strength of industrial, business, and community support for the Shell project. He also stated that Shell's project would have the following main advantages over Husky's project:

- greater positive economic benefits to the local community, and
- a safer and more efficient development of the Caroline and Bearberry reserves.

The Town Council was satisfied with the information that Shell had provided to the community and claimed that a new standard had been set by Shell regarding the incorporation of public input into project planning.

The Town was sceptical about the thoroughness and the readiness of the Husky project and expressed concern that the Husky project could result in long delays in initiating and completing the development. Mr. Guenther said that the people of the Sundre community did not want further unnecessary project delays.

3.16 County of Mountain View No. 17

Mr. S. Vollmin appeared on behalf of the County, supporting Shell for the following reasons:

- Shell's project is the only project which meets the County's criteria,
- it addresses the economic concerns of the individuals who are living in the sour gas field and assures some economic advantages to those same individuals,
- a new modern plant would be constructed so that negative environmental impacts would be greatly reduced, and
- shorter pipelines increase the safety level; and control and safety of long pipelines is a concern.

He said that Shell's Site E proposal would be the best location for the new plant; however, if it were found to be unacceptable, the new

plant should be located alongside the Shell Bearberry demonstration plant.

Mr. Vollmin said that people living in a sour gas field must have a say in the proposed development and should gain the maximum possible monetary benefit, which should stay in the local area. The County indicated that Husky's project would take away economic benefits from the Caroline area.

3.17 Caroline and District Chamber of Commerce

Mr. R. Bancroft appeared on behalf of the Chamber, which supported the Shell project, stating that

- Shell exhibited a genuine interest in the safety and development of the community,
- the Shell project would promote more trade and economic growth in the Caroline community,
- a plant at Shell's proposed site would be far safer than pipelining the sour gas 55 km, and
- it could better accommodate production from the Bearberry reservoir.

The Chamber stated that since the Caroline area residents would be subjected to sour gas risks, they deserve the economic benefits. It also stated that the Caroline area has the infrastructure to handle the influx of people that would occur from the development.

3.18 Olds and District Chamber of Commerce

Mr. J. Smith appeared on behalf of the Chamber, which supported the Shell proposal for the following reasons:

- the Shell project would result in a more equitable distribution of economic benefits among the communities like Olds and also where the resource is being extracted,
- Shell had undertaken a more consultative and comprehensive planning approach,
- its project would ensure the orderly incorporation of the Bearberry reservoir, and
- Shell's proposal would more appropriately address environmental impacts and risk issues.

The Chamber claimed that Shell had developed a reputation as a good corporate citizen.

3.19 Sundre and District Chamber of Commerce

Mr. D. Dewinetz appeared on behalf of the Chamber, which supported the Shell project. He stated there would be greater potential for real growth, development, and economic benefits in the Sundre area during construction and operation of Shell's project.

The Chamber referred to the May 1989 convoy in which the business community of Sundre joined together to show support for Shell. The Chamber said that Shell has been an excellent corporate citizen, and its commitment to the environment is evident in Shell's voluntary reduction of emissions at its Burnt Timber processing plant. The Chamber claimed that benefits from the Husky proposal would be almost nil for Sundre and area. It indicated that pipelining sour gas over long distances would result in needless risks when there is a better alternative.

3.20 CP

CP, which supported the Shell project, stated that it was the successful bidder against competitors for the contract to transport the Caroline sulphur production to Vancouver for export. CP noted that its route to Vancouver would be some 1100 km long compared to approximately 1600 km for its competitor. It

stated that there were no circumstances under which CN's freight rate could compete with the rate CP had offered to Shell.

3.21 Diamond J. Industries Ltd.

Mr. J. Bandura, who represented Diamond J. Industries Ltd., expressed support of the Shell project. He noted that CAB represents a large number of people and that CAB supports the Shell project, and suggested the ERCB should consider the wishes of residents in the project area. He expressed concerns about Husky's job contracting practices and questioned Husky's financial viability.

3.22 Canadian Hunter

Canadian Hunter stated it does not have a working interest in the Caroline reserves, but appeared at the hearing to present its views regarding the Board's disposition of the applications. It had no preference regarding the two proposals, but claimed the applications were unique and the Board should refrain from setting general principles as part of its decision that may affect industry as a whole. It suggested that because of the nature, size, and high H_2S content of the Caroline reservoir, the decisions arising from these proceedings should not necessarily be applied to future more conventional gas plant applications.

3.23 NOVA

NOVA appeared at the hearing and filed a letter of intervention which provided information with respect to facilities that would be required for each proposal. NOVA expressed no preference for either project.

3.24 Burnstick Lake Cottage Owners' Association

BLCOA appeared at the hearing and stated its main concern was to maintain the pristine nature of the lake, the purity of the air, and the tranquillity of the environment. BLCOA said the Caroline reserves should be developed, but only if there is appropriate regard for both the public and the environment.

BLCOA retained International Management Associates Ltd. (IMA) to examine various aspects of both projects and make recommendations. IMA and BLCOA conducted joint reviews of each proposal with the respective proponents and examined the following issues:
- critical wildlife habitat loss,
- climatology and air quality,
- risk analysis and emergency response planning,
- impacts to water and aquatic fauna, and
- security concerns.

BLCOA stated that environmental impacts associated with either proposal must be dealt with by the Board so that, through avoidance or mitigation, there would be no net loss of use or value of the environmental attributes of the area, and the safety of local residents and their property would be protected.

BLCOA recommended the operator of the approved project be required to do the following:

1. Design and implement a 5-year regional biophysical monitoring program in conjunction with local organizations and government agencies.
2. Establish a full-time air quality monitoring station and program in the Burnstick Lake area.
3. Establish and include the Burnstick Lake Cottage Development in a secondary response plan which would consider wind direction as well as the potential for loss of life external to the primary response planning area.

4. Install two permanent first alert warning systems at the Burnstick Lake Cottage Development and the public campground which would give audible warnings of a hazard when the primary emergency response plan is enacted.
5. Implement a security measures program by retaining qualified security guards to visit the Burnstick Lake Campground and Cottage Development three times daily during construction of the Caroline facilities. The security program should be augmented with full-time evening surveillance between 20:00 and 02:00 hours during May to September. A public phone should be installed in the area of the subdivision boat launch and all phones should carry appropriate signage encouraging the reporting of suspicious, malicious, or inappropriate activities.
6. Design, fund, and implement a 5-year regional social impact study to monitor social change within the successful applicant's project area. The findings of this study should be reviewed on a yearly basis through a community-organized Operations Committee comprised of representatives from the petroleum industry, the ERCB, the municipal district, Alberta Environment, and affected community organizations.

3.25 The Alberta Fish and Game Association

Mr. I. Johannson, who appeared on behalf of the Association, claimed that every industry should assist in preserving the habitats of fish and wildlife so that these resources may be sustainable. To offset the potential damage in these areas from the Caroline development by either applicant, the Association wanted to ensure that a net gain in fisheries and wildlife habitat would occur. It also suggested that new access in the project area be kept to a minimum.

3.26 Rocky Mountain House and District Chamber of Commerce

The Chamber favoured the Husky proposal for the following reasons:
- the Husky project would support the existing economy in the Rocky Mountain House region,
- it would promote growth of the economy in the M.D. of Clearwater,
- the economic activity generated by workers at camps would be spread over a broader area, and
- the Caroline reservoir has created an opportunity for the Ram River plant, which is one of Alberta's largest SO_2 emitters, to make a substantial reduction in its emissions.

The Chamber accepted that there may be a higher risk with transporting sour gas via a 55-km pipeline for processing. However, it added that the difference would be small enough to be acceptable when considered with the environmental benefit of the Husky project.

The Chamber said that Husky has proven to be a good corporate citizen in the Rocky Mountain House region.

3.27 CN

CN, which presently transports sulphur from the Ram River gas plant to Vancouver, favoured Husky's project for the following reasons:
- the Ram River gas plant is currently not fully utilized,
- high utilization of those facilities would ensure the continued use of about 200 km of CN's existing rail line serving Husky's plant, and continuation of the current associated jobs,

- Husky's proposal would avoid the need for a large new gas plant and sulphur handling facilities, and
- there would be a reduction in SO_2 emissions in the Rocky Mountain House region.

CN stated that although its route to Vancouver was longer than the proposed CP line, the grades on its system were much lower and therefore the difference in fuel requirements for the two systems would be insignificant.

CN said that in the event the Board determined that Shell's project should be approved, the alternative of the liquid sulphur pipeline going to existing sulphur handling facilities at Ram River rather than to Shantz should be considered. CN indicated this option could result in the following benefits:

- cost savings of approximately \$20 to \$35 million depending on the extent of upgrading required at the Husky Ram River sulphur handling facilities, and
- full utilization of the Husky Ram River and CN sulphur forming, handling, and shipping facilities would be assured.

CN suggested that Shell's approval should contain a clause requiring a full assessment of this option. It added that if the detailed review showed the capital costs, environmental considerations, and employment benefits were superior in the Ram River option compared to the Shantz proposal, Shell should be required to construct its liquid sulphur pipeline from Site E to Ram River.

3.28 Town of Rocky Mountain House

The Town Council indicated that the Husky project has a number of advantages over the Shell project, including:

- greater benefits to all areas,
- long-term viability of an existing plant as well as creation of significant new employment and business opportunities throughout the region, not just Rocky Mountain House,
- environmental benefits,
- use of proven technology, and
- no major new facilities would be required.

3.29 Concerned Residents Action Group

CRAG appeared at the hearing on behalf of 43 families living in the vicinity of the gas plant sites proposed by Shell and Husky (Site E). CRAG retained a number of experts to review Shell's applications and to help identify areas for possible concern. The group's concerns, which were presented at the hearing by some local members and their experts, included plant proliferation, wildlife, noise, site selection, groundwater contamination, future development, emergency response planning, emissions, soil and vegetation, quality of life, health, and property values.

Both Shell's proposed plant and compressor station locations were evaluated and CRAG concluded that several alternative sites may be as appropriate as the proposed locations. It suggested that other locations farther away from wildlife habitat areas and from residents should have been considered. It also suggested that the Board and Shell should reconstitute a site selection panel, including local residents, to examine the data gathered to date and select more appropriate plant and compressor sites. (This matter is discussed further in Section 11.5.)

CRAG reviewed the surface water matter related to Site E in Shell's proposal and claimed that extensive grading would be required to ensure that contamination from runoff would not occur. CRAG indicated that runoff and its relation to wetlands is a complex matter and should be given further consideration along with the sensitivity of wetlands to runoff reduction, sulphate deposi-

tion, airborne and waterborne contaminants, and possible chemical and fuel spills.

CRAG also evaluated the surface waters in the general Caroline area and suggested there is abundant evidence that the quality of water in area streams and the life in those streams are already declining as a result of various developments. It disagreed with Shell's view that by implementing mitigative measures during construction of roads and pipelines there would be no significant impacts on wildlife or fisheries.

CRAG conducted a groundwater review of Site E and addressed the potential for groundwater contamination. It agreed with some of Shell's conclusions that a low permeability, thick clay layer underlies Shell's proposed plant process area. However, CRAG said there are topographic lows in the general plant area, and claimed that because of the possible thinning of the clay layer in those lows, the underlying gravel bed could act as a pathway for off-site migration should contaminants move downward through that potentially thin clay layer. CRAG suggested that additional test drilling in the topographic lows would be advantageous to obtain more data.

CRAG examined the effect of Shell's proposed plant on land values in the area and disagreed with Shell's suggestions that there would be no effect on property values in the vicinity of large sour gas facilities. CRAG claimed that recreational or residential property would be less attractive to potential buyers as a result of a large sour gas facility and suggested that one way of easing the impact would be to reduce the size of the facility.

CRAG's experts evaluated the wildlife section of Shell's EIA and said the matrix method which Shell used did not reflect the public's best interests. CRAG stated that environmental issues should not be dealt with using a matrix, as wildlife issues alone could have resulted in the selection of another plant site. CRAG's experts also commented on a perceived shortage of baseline wildlife data for the Shell proposal.

The group evaluated the transportation aspects of Shell's application and claimed there would be significant changes in traffic during and after construction of the proposed Shell facilities. CRAG said that increases of up to 1480 per cent in traffic could be expected.

CRAG made the following recommendations:

1. Husky's project should be approved.
2. Jointly with area residents, Husky should be required to determine if its proposed Caroline gas transmission plant could be relocated to the proposed central compressor station.
3. In regard to the compressor stations, CRAG stated that Shell be required to review the compressor station locations to determine whether there are superior locations for the compressors and, following such an analysis, submit the data to the Board for subsequent approval.

CRAG also stated it endorsed the recommendations put forward by Dr. Kostuch and PALSS.

3.30 The Preservation of Agriculture and Living Space Society

PALSS stated that it supports orderly development. To fully assess Shell's and Husky's applications, it retained experts (Norecol) to make a comparison of the two proposals. As a result of this review, PALSS and its experts expressed concerns which included

- the need for long-term health studies,
- sulphur forming and dusting,
- air and water quality,
- soil acidification,

- engineering reliability,
- plant proliferation,
- land use, wetlands,
- effects on agriculture and livestock,
- socio-economic impacts,
- traffic,
- aesthetics, and
- welfare of future generations.

The PALSS experts said that from an engineering standpoint, both proposals were sound. They determined that contamination of surface and groundwater by sewage and sedimentation of streams from construction of either project were unlikely. PALSS did not see any potential for negative impacts on surface waters from waste water ponds, nor risks to surface or groundwater from the disposal of produced or process waste water. PALSS concluded that the potential for impacts to soil and vegetation would be the same for either project. It said that Shell's proposed liquid sulphur pipeline would have a very low risk for a line break or spill and even if this were to occur, the consequences would be minimal.

Following its comparative review of the two projects, PALSS said it preferred the Husky proposal for the following reasons:

- it would have lower sulphur emissions,
- it would have fewer visual impacts, and
- traffic and noise would be less in the areas inhabited by the PALSS members,

PALSS recommended that the operator of the approved project be required to do the following:

1. Conduct future sampling programs to obtain data on heavy metal emissions.
2. Have proper baseline environmental studies respecting air, water, and soil conducted in the project area by third parties and the results be made public.
3. On-going monitoring be conducted as in 2. above,
4. A proper long-term health study be carried out to permit on-going monitoring of any health changes in the project area.
5. Should there be a community consultive process, such an organization should include broad-based interest groups including members of PALSS.

PALSS also stated that if the Husky project were approved, Husky must fulfil its commitment to mitigate its groundwater contamination and to modify or adopt better technology to reduce sulphur dusting at Ram River. However, if Shell's project were approved, it should have to adhere to its commitment not to utilize a railway in the Caroline/Sundre area to transport sulphur. Additionally, PALSS supported CN's recommendation to have Shell construct the proposed liquid sulphur pipeline to Ram River. PALSS stated this would eliminate the need for a new industrial development in the Shantz area.

3.31 L. and J. Bauman

The Baumans appeared at the hearing and raised general concerns which included the following:

- SO_2 emissions,
- the impact of heavy metals and other contaminants on the environment, human and animal health and crops,
- soil testing,
- sulphate deposition, and
- perceived falsities in the EIAs.

They indicated they favoured Husky's proposal.

3.32 J. and L. Brunner

The Brunners, who presently live in Calgary, also have a country residence in the SE 1/4-17-34-4 W5M. They said their dwelling is

within 2.0 km of a sour gas well, the proposed south compressor site, and the existing Amoco South Caroline gas plant. Mrs. J. Brunner said she has been diagnosed with lupus erythematosus and believes exposure to noxious fumes would increase her health risks. She stated that she is opposed to any development, but if one proposal is to be approved, she preferred Husky's option. Mrs. Brunner also requested that the south compressor be relocated. (This matter is dealt with in Section 11.5.) If an approval were granted, Mrs. Brunner said that certain preventative or mitigative measures should be taken to protect her safety and that of her family. Those measures include:

1. The incorporation of post-approval negotiations on compressor site selection.
2. An emissions monitoring program with a monitor on her property that would automatically sound an alarm at very low emission levels.
3. A second emissions monitor on her property which the family could read.
4. Emergency and safety equipment on her property.
5. Help and co-operation from the oil and gas industry to develop an effective antidote for the effects of sour gas.
6. Establish barriers to deflect sour gas emissions in case of an H_2S release or pipeline rupture.
7. Increased setback requirements from pipeline facilities and wells.
8. Consideration of a cap on emissions.

The Brunners also expressed a dislike for the phone system method of notification and personal visits by operators during emergencies because of the length of time involved to accomplish them.

3.33 D. and M. Harris

The Harris family lives in Calgary and also has a residence and property at SW 10-33-7 W5M, about 5.6 km southwest of the Bearberry gas pool. Mr. D. Harris expressed a number of concerns including the following:

- safety,
- quality of life,
- the well-being of the biota,
- traffic,
- property values,
- fair compensation, and
- retirement plans.

Mr. Harris, who has a honeybee operation, stated that honeybees are susceptible to many of the emissions associated with the oil and gas industry. As the Ram River plant is not in the vicinity of agricultural lands, he favoured Husky's proposal.

3.34 J. Hermann

Mr. J. Hermann, who owns land at SW 1/4-9-36-6 W5M, expressed concerns about sour gas flaring and SO_2 emissions which he said caused risks to humans and animals. He indicated there must be a balance between environmental quality and hydrocarbon production and said that although those balancing costs today would be great, future costs would be much more significant. Mr. Hermann suggested that the clean-up of existing plants prior to approving more new plants would be more in the public interest.

3.35 E. and B. Jans

Mr. and Mrs. Jans appeared at the hearing and requested that the submission of CRAG be considered representative of their general views. Their concerns included

- flaring,
- noise,
- plant proliferation, and
- emergency response planning and traffic.

They indicated support for Husky's project, and expressed confidence that the Board's

decision would be the fairest for the development of the Caroline reserves.

3.36 Dr. M. Kostuch and RVC

Dr. Kostuch filed an intervention and appeared at the hearing on behalf of herself and the RVC. She expressed concerns about current conditions and the proposed Caroline development, stating the following:

- there are significant emissions of sulphur from existing gas plants located along the Rocky Mountain foothills and the continuation of present patterns of sulphur deposition would result in extensive damage to the forest ecosystems in the region, and
- little scientific investigation has been done on the effects of sulphur deposition on these forest ecosystems.

Dr. Kostuch stated that she was not opposed to the development of the Caroline sour gas reserves provided the processing and development could be done with minimal impact to human and animal health and forest ecosystems.

Dr. Kostuch said that after considering both Shell's and Husky's applications, she concluded the critical difference between them was the amount of sulphur emissions that would likely occur from each respective project. She stated there was a need for an absolute reduction in the rates of sulphur deposition in the region, as in her opinion, the paramount environmental issue was sulphur deposition on a regional scale.

Dr. Kostuch said there is a lack of baseline data and "hard" scientific evidence to prove that the ecosystem in the region has been damaged or adversely affected by sulphur deposition. To assist her in this area, she retained Mr. T. Bouman whom she stated was a scientist experienced in assessing the damage to forest ecosystems created by sulphur deposition. Mr. Bouman reviewed the EIA for the two proposals. He claimed that current air quality modelling is not an adequate tool for determining potential for forest damage. He said that forest decline is readily visible in the vicinity and downwind of the Ram River plant. To support his claim he provided a slide presentation showing damaged trees. He also conducted a site visit to the area for the Board and interested parties to illustrate his concern. He acknowledged that damage to the root systems of the forest in the area can be expected and emphasized that the best method to combat this would be to reduce overall emissions.

Dr. Kostuch suggested that in order to prevent potential further damage, the application that offers the lowest overall rate of sulphur emission in the region should be approved. The emission rate comparison should include the sulphur from the gas currently being processed, the Caroline gas, and the Bearberry reserves. She also suggested that the successful applicant be required to commence scientific work at once to determine what is happening in the regional forests in terms of accumulated acidity and buffering capacity of ecosystems, and estimate what changes would occur if the levels of sulphur deposition continued.

If either application is approved, Dr. Kostuch recommended that the following conditions be attached:

1. A declining limit for SO_2 emissions in the issued permit in accordance with the anticipated decline in the available reservoirs. This would ensure that the issue of SO_2 emissions will be reviewed when and if there are applications to process new reserves at the Ram River gas plant.
2. The proponent be required to extend the data base for forest risk assessment.

3. The proponent be required to select sites and monitor rain and throughfall chemistry and other parameters.
4. The proponent be required to complete additional experiments on sensitivity of regional tree species to soil chemistry and on the effects of soil structure on soil chemistry.
5. A condition in the permit requiring that monitoring data, and remediation programs, and results be filed with the Board and Alberta Environment and be made available to the public upon request.
6. Approval of the foregoing programs by Alberta Environment following consultation with the public and interveners.
7. Consideration be given to monitoring ground-level ozone concentrations and further testing on the synergistic effects of ground-level ozone and SO_2.
8. The proponent be required to develop a plan to evaluate the social and environmental impacts of the project and audit the success of the EIA and SEIA in predicting, monitoring, and mitigating the impacts of the project. The evaluations and audits should be filed with the Board and Alberta Environment and be made available to the public upon request.

If Husky's application is approved, she recommended that the following additional conditions be attached:

1. Remediation of the groundwater problems at the Ram River plant site.
2. Remediation of sulphur dust problems at the Ram River plant site.

3.37 R. E. Wolf

Mr. R.E. Wolf said his family owns property in the Wildcat Hills area in the NW 1/4 28-27-5 W5M. He claimed there is no need for the production of the Caroline sulphur and gas at this time and said he was concerned about Shell's methods of operation. He said he endorsed the report of CRAG's experts which evaluated Shell's EIA, and argued that the Caroline development should be denied or delayed.

Mr. Wolf said there is a need for long-term baseline studies. He expressed a concern that there is no pollution tax to provide incentive to clean up and believes that all waste gas and liquid effluent should be disposed of into the Devonian Formation.

3.38 The Pollution Sub-Committee of the Public Advisory Committees–Environment Council of Alberta

The Pollution Sub-Committee was represented by Dr. P. Ramalingam who indicated the intervention concentrated on the environmental impacts of the respective applications. He said that SO_2 emissions are a significant issue and should be an important factor in the Board's consideration of the applications. He recommended that Husky's project be approved for the following reasons:

- expansion of its existing plant would result in a reduction of regional SO_2 emissions, and
- it is feasible to expand the Ram River gas plant, therefore there is no need for another gas plant.

He also recommended that the Board consider the implications of the CO_2 emissions from the Caroline development.

3.39 Other Interveners

The following parties submitted separate interventions in support of Shell, but did not appear at the hearing:

DEKALB
Home
Norcen
PanCanadian
G. E. Allison Construction Ltd.
Sundre Emergency Medical Society
Sundre General Hospital
A. Macklin

The following parties submitted separate interventions that did not support or oppose either applicant. Additionally they did not appear at the hearing:

A. Ludwig

MD of Clearwater No. 99

4 BASIS OF DECISION

4.1 Overall Approach

The Board is in the somewhat unusual situation of having before it competing applications for a major gas processing project. Each of the Shell and Husky proposals would involve the processing of all of the production from the Caroline Beaver Hill Lake gas reservoir and therefore are mutually exclusive. Additionally, although there is clearly a need for gas processing and related facilities to make the large Caroline reserves marketable, the Board received no evidence which would suggest that more than one project would be in the public interest. It follows that only one of the projects, as put forward, could or should proceed.

The Board considered a number of ways in which it could evaluate the competitive applications. For example, the Board could assess the overall acceptability of both applications from a public interest viewpoint and if they were both acceptable, indicate that it is prepared to approve either of them. The commitment of the gas reserves to one or another of the applicants, through normal business decisions, would then decide which of the projects should proceed. An alternative approach would be to assess the overall acceptability, and also to carry out a comparative analysis of the two projects. The proposal judged to be most in the public interest would be approved.

The Board must assess the acceptability of the projects in terms of the public interest and this appeared to be agreed to by all participants at the hearing. Shell took the position that if the project proposed by the majority of Owners was found to be in the public interest, that project should be approved over any competing proposal. Husky's position was that the Board should do a comparative analysis of the two projects and approve only that which is judged to be the best. Husky stated that the preference of the Owners should be considered but should not be pivotal in the decision.

The Board is satisfied that it should make a comparative assessment of the public interest aspects of the competing applications. In doing so, the Board recognizes that the factors that make up the public interest vary with the circumstances and are judgemental and the weight the Board attributes to many of the factors in its final decision has to be, in large part, qualitative in nature.

4.2 Public Interest Criteria

The Board has developed a list of criteria which it considers relevant to the public interest in this particular case. In doing so, it has had regard for the purposes section of the Oil and Gas Conservation Act (Act) under which the subject applications have been brought before the Board. That section reads in part:

"*4. The purposes of this Act are*

- *a) to effect the conservation, and to prevent the waste of, the oil and gas resources of Alberta;*
- *b) to secure the observance of safe and efficient practices in the locating, spacing, drilling, equipping, completing, reworking, testing, operating and abandonment of wells and in operations for the production of oil and gas;*
- *c) to provide for the economic, orderly and efficient development in the public interest of the oil and gas resources of Alberta;*
- *d) to afford each owner the opportunity of obtaining his share of the production of oil or gas from any pool;*
- *e) . . .*
- *f) to control pollution above, at or below*

the surface in the drilling of wells and in operations for the production of oil and gas and in other operations over which the Board has jurisdiction."

On the basis of the above quoted sections of the Act and the views expressed by participants in the hearing, the Board believes the following criteria would influence the overall public interest:

- economic efficiency,
- technical feasibility and operating reliability,
- resource conservation,
- environmental impacts,
- risk to public safety,
- socio-economic impacts,
- public acceptability,
- future resource development potential, and
- impact of related applications (necessary industrial infrastructure such as pipelines and electric transmission facilities).

The above factors are not listed in order of importance but in the sequence in which they will be dealt with in this report.

The Board recognizes that there is an interrelationship and some overlap between most of the factors. For example, matters such as operating reliability may influence other criteria, particularly economics, environmental impacts, and risk to public safety. Nevertheless, the Board in this case considers each of the listed criteria to be sufficiently important that it will deal with each separately. In doing so, the Board has taken care to not double-weight the importance of the factors, as was cautioned against by some participants in the hearing.

4.3 Working Interest Owner Preference

There was much discussion at the hearing of the importance of Owner preference and the role it should play in determining which proposal should be approved. The Board believes that the preference of Owners is a factor which influences the overall public interest in several ways. For example, it contributes to orderly and efficient development.

In this particular case, the Shell proposal is put forward on behalf of the Owners of some 89 per cent of the Caroline reserves. It thus has a clear advantage, in this regard, when compared with the Husky proposal which represents the preferred development project for the Owners of only some 11 per cent of the reserves.

Notwithstanding the Board view that Owner preference is a factor which influences the public interest, the Board does not believe it is a dominant one. In a situation where competing applications are before the Board and one project is judged, in terms of public interest, to be clearly superior to the other, the Board would approve the best application, whether or not it is the one preferred by the majority of Owners. The Board would take this action because it believes its responsibilities to protect the public interest justify overruling the preference of the Owners where there is a clear public interest reason to do so.

5 ECONOMIC EFFICIENCY

5.1 Introduction

Economic efficiency, as used in this report, is a measure of the total economic benefits which would be generated by the proposed projects. The Board, on the basis of the information presented at the hearing, has made an estimate of the time of start-up and of the capital and operating costs for each project, along with the total revenue that would result. The differences between the revenue and costs of the projects have been appropriately discounted to show a total net present value and allow a comparison of economic efficiency. The relative economic efficiency of the two projects has been assessed by the Board because economic efficiency affects the total potential benefit of the project, for example in terms of taxes and royalties. Therefore, improved economic efficiency is in the public interest.

This section of the report deals with total costs and revenue for the proposed projects. (Socio-economic impacts and benefits are discussed in Section 10.)

5.2 Cost-benefit Analysis

Husky presented a cost-benefit analysis which included not only an assessment of revenue and expenditures, but also estimates of certain other less tangible costs and benefits, such as those associated with the emission of increased amounts of SO_2. Husky suggested that such a cost-benefit analysis would be a further useful tool for the Board to use to assess the relative merits of the proposals. Shell doubted the value that a cost-benefit analysis would provide, but did present its own version of such an analysis, generally using the format followed by Husky.

Although the Board acknowledges that a cost-benefit approach can be useful to screen certain public policy issues, it questions its real value in assisting the Board to reach a decision respecting the Shell and Husky applications. While the cost-benefit framework offers a quantitative result, the methodology is a subjective exercise. It incorporates a host of assumptions about project economics and values society may place on related factors. For example, the Board does not believe that selective environmental impacts or risks to public safety can be as readily expressed in financial terms as those related to project cash flows. Such calculations tend to involve long-term effects and are subject to a high level of uncertainty. Given those uncertainties, the Board believes the cost-benefit results would be inconclusive in this instance and accordingly it has decided not to use the analysis as presented at the hearing.

5.3 Timing

The economic efficiencies of the proposed projects would be affected by the dates at which they could be completed and placed in operation. As a result, during the hearing considerable attention was focused on the likely plant commissioning dates. Shell indicated that if it receives the required approvals by July 1990, construction of its proposed Caroline gas plant would start in the autumn of 1990 and it could be commissioned by December 1992. Shell stated that it is well advanced in its facilities engineering and design, and added that some 400 thousand man-hours of engineering work was done prior to filing its applications.

Husky indicated that although its engineering and facilities design work was not as advanced as Shell's, it expected to execute interim and

letter agreements with the other Caroline Owners in the months immediately following its project's approval, at which time it would then proceed with the detailed engineering work. Husky stated that, to date, some 30 thousand man-hours of engineering work has been put into its proposal. Husky suggested that if it received approvals in July 1990, plant design could commence in October 1990 with site construction commencing in the spring of 1991. Husky said its project could be commissioned early in the second quarter of 1993.

It is evident to the Board that Shell's planning and engineering is well advanced relative to the Husky proposal. The Board expects that any lag in engineering work would likely delay Husky's earliest start-up date beyond the date projected in its application. The Board notes that Husky would not resume detailed engineering until at least interim commercial arrangements have been put in place and the other Caroline Owners have agreed to join the Husky project. The Board estimates that, at best, it may be 3- to 6-months after approval before commercial arrangements would be in place so that design work could continue. There would likely be a further 3 to 6 month period before Husky's project design would reach Shell's current stage.

The Board also believes the integration of new equipment with the existing Ram River plant facilities could bring about unforeseen complications and make the construction phase longer than forecast by Husky.

Based on the foregoing, the Board concludes that it is highly unlikely the Husky project would be completed in the time frame indicated by Husky. It is the Board's view that the on-stream date for the Ram River plant expansion project would be at least 6 to 12 months later than for the Shell project.

5.4 Capital Costs

Capital cost estimates for both the Shell and Husky proposals were discussed extensively at the hearing. Shell estimated total capital expenditures of $825 million (1990$)[(5)] for its project, while Husky estimated a cost of $756.6 million for its proposal. Shell, through its consultant Delta, provided what it called a "comparable estimate" of costs of $886.7 million for Husky's project, which was significantly higher than Husky's estimate.

While Shell's estimate of $825 million for its proposal was accepted by both parties, the Husky project estimates were subject to long debate regarding their credibility and accuracy.

In light of the extensive engineering work done by Shell and the details provided in its submission, the Board believes that the Shell estimates of capital costs for its own project are reasonable and acceptable. The Board, however, is not able to accept the estimates put forward by Husky for all aspects of its project.

The Board does accept the Husky estimates, totalling some $446 million, for the field and gathering system, Husky's proposed gas transmission plant, sour gas transmission pipelines, oxygen plant, and infrastructure. It does so, even though it believes that the stage of engineering work is such that there is potential of higher costs in some of the estimates.

With respect to the remainder of Husky's estimates for modifications to the Ram River gas

(5) All costs referred to in this report are given in 1990 dollars.

plant and startup costs, the Board notes that the estimate totals some $310 million. The comparable estimate presented by Shell for the Husky proposal is some $444 million, a difference of $134 million or over 40 per cent.

Husky did not provide a detailed cost estimate of its plant components. While it is evident that fewer equipment costs would be necessary to expand the Ram River plant compared with the new plant proposed by Shell, the Board believes that the cost of retrofitting existing and installing new equipment at an expanded Ram River plant would likely offset at least a portion of the cost difference between the Husky and Shell proposal. Indeed, the Board is concerned that retrofitting costs can sometimes exceed the equivalent new plant costs because of matters such as custom building of the new equipment, unforeseen problems of fitting new equipment with old, and required future replacement of existing equipment. Retrofitting can also create start-up problems.

In making its estimate of the capital costs for retrofitting the Ram River plant, the Board had regard for the estimates by Husky and also those put forward by Delta on behalf of Shell. The Board concludes that the costs would likely be somewhere between the two estimates. In particular, the Board believes the costs for the gas treating facility, modified sulphur plant, SCOT units, and utilities were over-estimated by Delta. Although detailed comparable estimates were not available, the Board believes these facilities were under-estimated by Husky. Additionally, the Board believes that Husky has under-estimated its likely start-up costs.

After reviewing the above-referenced items, the Board believes that the Husky estimate for modifications to the Ram River plant is low by at least $50 million. This would mean the total cost of the Husky project would more likely be in the order of $800 to $810 million compared to $825 million for the Shell project. For its analysis, the Board has estimated that the Husky project capital costs would be some $805 million.

Recognizing the limited engineering work done by both Husky and Delta on cost estimates for the Ram River plant expansion, and the nature of major retrofitting projects, the Board also concludes that there is considerably greater uncertainty respecting the Husky project cost estimate than is the case for the Shell project.

5.5 Operating Costs

The operating costs provided in the Shell and Husky proposals were similar. The first year operating cost provided by Shell amounted to some $40 million. This cost would likely decline over the project's life as the variable portion of the operating cost declines because of lower throughput. The Husky estimated operating cost amounted to $38.8 million in the first year of full operation, and for the same reason is expected to decline over time.

The Board believes that Husky's operating costs are slightly under-estimated for factors such as power costs. For this reason the Board, for its analysis, used similar operating costs for both projects.

5.6 Conclusions Respecting Economic Efficiency

The Board has evaluated the Shell and Husky proposals and finds that both projects are commercially viable, and the present worth value of both projects is similar, with a slight advantage to Shell's project over Husky's.

For its analysis, the Board used on-stream dates of December 1992 for Shell and September 1993 for Husky, and capital cost

estimates of $825 million for Shell and $805 million for Husky. Similar operating costs were used for both projects.

The Board's analysis indicated that the Husky project would yield slightly over $3.5 billion in present value benefits, using an 8.0 per cent real discount rate, and a net benefit of almost $2.5 billion. The Shell project would provide for some $3.7 billion in present value benefits, and a net benefit of slightly over $2.5 billion.

Therefore, it would have a small advantage over Husky's proposal in terms of economic efficiency. That advantage is somewhat increased by the greater degree of uncertainty in the cost estimates and commissioning date for the Husky project.

6 TECHNICAL FEASIBILITY AND OPERATING RELIABILITY

6.1 Introduction

The Oil and Gas Conservation Act and Regulations require proponents of all new facilities or project expansions to demonstrate, in their applications, that a proposed project is technically feasible and would operate reliably. With respect to the two competing Caroline projects, certain hearing participants discussed technical feasibility and operating reliability as matters which could result in one proposal being considered superior to the other. For this reason, the Board believes it is appropriate for the purpose of this decision to comment on the applications with respect to technical feasibility and operating reliability, giving particular consideration to the potential for flaring of sour gas.

6.2 Technical Feasibility

6.2.1 Field Facilities

Shell filed formal applications for the field facilities and gathering system, including the three proposed field compressor stations. Husky stated it fully supported Shell's Caroline field and gathering system applications and was primarily proposing an alternative gas processing option to Shell's project. Although a few of the hearing participants suggested that alternative compressor station locations should be considered by the successful applicant, the Board notes that the majority of residents in the area of the proposed field facilities did not oppose or object to the gathering system and field compressor applications. (This matter is discussed further in Section 11 of this report.)

The Board has reviewed the equipment and design of the proposed wells, flow lines, and compressor stations and notes that these facilities would meet or exceed the Board's technical requirements. Each component would be sized and designed appropriately to ensure that the Caroline fluids could be safely delivered from the reservoir to the proposed Site E processing facilities on a continuous basis with minimal and infrequent flaring in the field. The Board also notes that field facilities of similar size and design have been operating successfully in various populated and unpopulated areas of the province for a considerable period of time.

Both proponents stated that in the event of an upset or equipment shut-down, their respective projects could use high-pressure sweet fuel gas to purge raw sour gas from the individual wells to the compressor stations and then on to the gas plants. In Shell's case, the purging would end at Site E. Husky stated it would also have the ability to purge its proposed sour gas transmission pipelines to its Ram River plant. Although the purging feature is technically feasible, there was a lack of detailed data presented at the hearing as to how each operator would accomplish the sweet fuel purging under various scenarios and whether sufficient purge gas volumes would be available. Both applicants also stated they would utilize various leak detection procedures at their facilities but neither provided a clear description of their proposed systems. Therefore, the Board will require that the successful applicant provide appropriate details about the sweet fuel gas purging system and its operation and the leak detection systems and procedures.

6.2.2 Gas Plants and Sulphur Recovery Levels

Both Shell and Husky propose to use generally the same processing technology, including Sulfinol gas sweetening to treat the Caroline feedstock, molecular sieve gas dehydration, hydrocarbon liquids recovery using a turbo-

expander, and Claus sulphur recovery units followed by two SCOT tail gas clean-up units for further sulphur recovery. Both Shell and Husky propose to use oxygen-enrichment in their sulphur recovery units. Husky would install this at the outset to provide capacity for Caroline gas, while Shell would install this later to provide capacity if Bearberry gas was found to be commercially viable.

Shell

Shell would initially install air-based Claus sulphur plants to recover up to 4500 t/d of inlet sulphur from the Caroline reservoir. When Bearberry commercial production occurs, Shell would install 70 per cent oxygen-enrichment to provide about 3500 t/d additional sulphur processing capacity. When questioned why it did not propose to use oxygen-enrichment at Caroline at the outset, Shell maintained that additional time was desirable to allow for further evaluation and development of oxygen-enrichment technology to minimize scale-up difficulties. Shell also stated that it would not be economically advantageous to incorporate oxygen-enrichment for only the Caroline reserves.

Although Shell was very confident that it could achieve 99.8 per cent annual average sulphur recovery after a suitable plant start-up period, it was reluctant to commit to a higher level as an approval requirement at the outset. Shell did, however, agree that the recovery level above initial requirements could be reviewed for possible upward revision after a suitable period of operating experience. Looking further in the future, Shell believed that it might ultimately be able to achieve a recovery level of 99.9 per cent as a result of converting to oxygen-enrichment technology, and recovering degassed sulphur vapours when the Bearberry production would be incorporated.

Husky

Husky's Ram River plant is currently approved to process and recover a maximum of 4660 t/d of inlet sulphur, but is presently processing an average of only about 2300 t/d because of the declining deliverability in the currently connected fields. To accommodate the additional 4500 t/d of inlet sulphur from the Caroline reserves, Husky would increase the plant's capacity to 6800 t/d by converting the existing sulphur recovery units from an air-based system to an oxygen-enriched operation using 39 per cent oxygen-enrichment. Further, Husky said that if Bearberry commercial production becomes viable, it could accommodate 3500 t/d of Bearberry sulphur as early as 1997 by going to 100 per cent oxygen-enrichment, and as a result of its predicted declining production from existing fields.

Husky committed to maintaining an overall annual average sulphur recovery level of 99.8 per cent and a minimum quarterly average of 99.5 per cent in accordance with the current provincial requirements. Husky declined to voluntarily commit to any level higher than the current requirements.

Shell questioned the likely operating reliability of Husky's Ram River proposal and argued that Husky would encounter difficulties in the conversion to and use of oxygen-enrichment at the existing Ram River plant. Shell stated that it had operated a 200-t/d commercial Claus oxygen-enrichment system at its Jumping Pound gas plant in late 1987. It argued that oxygen-enrichment technology is presently only proven to that rate but that Husky was proposing a manyfold scale-up. Shell said that with such a scale-up it doubted that a smooth plant start-up could be carried out. During normal operations, Husky's four Claus plants would be required to operate at about two-

thirds above their original design capacity. Shell suggested that long-term operation of the modified Husky sulphur recovery facilities could not continue at loads well above design rates without considerable downtime.

6.2.3 Conclusions Respecting Technical Feasibility

The Board is satisfied regarding the technical feasibility of the proposed field gathering facilities. It would, however, require greater details respecting the leak detection procedures and the sweet gas purge systems.

With respect to the technical feasibility of the two gas plants, the Board assessed a number of matters including oxygen-enrichment and attainment of the required sulphur recovery efficiency.

The Board believes the oxygen-enrichment proposed by Husky would be technically feasible, but its use on a very large scale at this time could cause some operational problems. The Board also believes that Husky's use of a large degree of oxygen-enrichment at this time may limit future expansion to accommodate other gas including the Bearberry reserves. In order to process other gas, Husky's plant would have to experience a sulphur inlet rate decline from existing fields and Husky would have to operate the Ram River plant's sulphur recovery facilities using 100 per cent oxygen-enrichment on a continuous basis.

During the hearing, both applicants indicated that the Caroline reserves should be processed at maximum load factors whenever possible. If the Ram River plant were fully loaded, Husky's sulphur recovery units, which were first installed in 1971, would have to continually operate at levels well above their original design rates. The Board is concerned that the high rates, combined with the need to continuously use oxygen to process the existing and Caroline reserves, may jeopardize plant operating reliability.

While the Board has concerns about possible difficulties with the oxygen-enrichment aspect of Husky's proposal, the Board recognizes that this technology has benefits of reduced fuel consumption and some incremental improvement in sulphur recovery. For these reasons, if the Shell gas plant were approved, Shell would be required to further review the feasibility of implementing oxygen-enrichment at its proposed Caroline plant at the outset of operations.

With respect to the technical feasibility of achieving an annual sulphur recovery level of 99.8 per cent for the Caroline gas, the Board believes that such an efficiency is attainable with Claus plants that incorporate SCOT tail gas clean up units, whether the Claus plants are new or existing. Either project should thus be able to attain such a recovery, although there may be additional operating complexities with the Husky proposal because of the immediate use of oxygen-enrichment and the loading of the Ram River plant. Further, the approval of either proposal would require that an annual average sulphur recovery of 99.8 per cent and a minimum quarterly average of 99.5 per cent be achieved. Also, a review of these recovery level requirements will be required after a suitable period of operating history.

In summary, the Board believes the two projects are technically feasible. However, because of the requirement for a high degree of oxygen-enrichment and continuous high throughput rates at Ram River, the Board believes the Husky project may experience greater start-up and operating problems. These could lead to additional costs, some downtime, and possible flaring, with attendant

environmental effects. The Board thus sees an advantage to the Shell project in terms of technical feasibility.

6.3 Operating Reliability

After a detailed analysis of all the exhibits and testimony, the Board believes both Husky's and Shell's proposals are acceptable, on their own merits, with respect to operating reliability. This is consistent with the previous section where the Board concludes that both projects would be technically feasible. The following analysis is primarily to compare whether or not one of the projects would have an advantage over the other in terms of operating reliability.

To undertake an appropriate comparison, the Board required a common basis on which the analysis could be conducted. Referencing the evidence and transcripts, in addition to its experience with existing facilities, the Board developed a series of probable failure and shut-down scenarios which were then condensed into four general categories and three sub-categories. The shut-down scenarios were a single well, a single field compressor, the complete gathering system, and a other facilities. This latter category was subdivided into the Site E plants, pipelines, and the Ram River plant.

Each of the scenarios was analysed to determine the likely frequency that a shut-down or failure may occur and the likely result, with emphasis on the potential for sour gas flaring. Differences, if any, between the projects were then established.

The Board does not expect any significant difference in the frequency of shut-down occurrences between the proposals, with the exception of shut-downs related to the Husky transmission pipelines and the Husky Ram River plant. This would cause a marginally higher frequency of shut-downs for the Husky proposal as it would involve a greater number of facilities.

In analysing the result of shut-downs, the most significant potential impact would be from sour gas flaring, particularly flaring which would occur in the Caroline area. The primary limiting factor in responding to shut-downs, for either project, would be the Caroline fluids hydrate temperature of 30°C. This hydrate point would restrict the amount of time available for an operator to appropriately manage an abnormal situation. Shell stated a maximum of 4 hours was available while Husky indicated that a shut-in of up to 6 hours could occur before hydrate control would be required. The Board accepts that the time would be limited and at maximum, would be only about 6 hours.

6.3.1 Field Facilities and Site E Gas Plants

Single Well Shut-down

The Board believes there is no real difference in the result of a single well shut-down between either proposal. The only potential for flaring sour gas at a well site would occur when either a flow line from the well to a compressor station was plugged by a hydrate which could not be removed by depressuring into the compressor station, or in the situation of a flow-line failure. In either case, flaring at the well site would be manually controlled and sufficient sweet fuel gas would be available for proper dilution by either operator. Such scenarios would be infrequent for either project and the results should not be serious.

Single Field Compressor Shut-down

Shell

The Board concurs with Shell that in the case of a single field compressor shut-down, Shell would be able to reduce the discharge pressure

of the remaining field compressors, reduce its Site E plant inlet pressure, and continue production and processing at a reduced rate because of the plant's dual train design. This would not require any sour gas flaring but may result in some small amounts of sweet gas flaring at Site E.

Husky

The Board accepts that, as proposed, Husky would have two alternative responses to this scenario which would enable production to continue. The first would be to lower pressures as described above in Shell's response. However, this would result in a lower discharge pressure from Husky's Site E compressors which would necessitate a reduction in the operating pressure of the transmission pipelines and the Ram River plant inlet pressure. Husky stated it had not examined whether sales specification gas could still be produced at Ram River with a reduction in pressure across the sweetening system. The Board believes that utilization of this option could result in some flaring of either sour gas or, more likely, off-specification sales gas at the Ram River plant.

The second Husky alternative, which was put forward by Shell, would be to isolate the segment of the gathering system that was shut down, because of a compressor shut-down, and depressure and flare that volume in the field at the affected compressor station, while maintaining full production from the balance of the gathering system. The Board believes this alternative may need to be used on some occasions. If used it would result in flaring of sour gas in the Caroline area rather than at Ram River.

Complete Gathering System Shut-down

The Board expects the same result from a complete gathering system shut-down as that described for the single field compressor shut-down. The second alternative available to Husky, depressuring the system and flaring the sour gas in the field, would not be acceptable in this situation as it would involve a larger volume of sour gas.

Processing Facility Shut-down (Site E)

Shell

The shut-down of the Shell plant at Site E would necessitate the depressuring and flaring of all sour gas within the gathering system and plant. Shell stated that such an incident would occur only if the entire TransAlta power supply system for the Caroline facilities plus all of Shell's proposed emergency power generation capabilities at Site E and at each compressor station failed simultaneously. The Board notes that in order to provide a reliable power network, Shell proposed to have TransAlta provide three independent 138-kV lines to Site E and separate radial feed lines to each compressor station. The Board also notes Shell's evidence that the likelihood of a total power outage at the proposed Caroline plant would be less than once in 5 years.

In the Board's opinion, this scenario would occur very infrequently, and if it did, the flaring would likely occur under controlled conditions at the plant site and the field compressor sites.

Husky

Husky stated it would be unable to continue production in this situation but would have the ability to by-pass its gas transmission plant at Site E and purge the sour gas from the wells into its sour gas transmission pipelines and through to Ram River for processing. The Board concurs, but expects that although this situation would not require any sour gas flaring in the Caroline area, it would likely result in some flaring of off-specification sales gas at Ram River.

6.3.2 Pipelines

The Board does not believe that operation of the Shell liquid sulphur pipeline in conjunction with the Shantz sulphur forming facilities would have any significant negative effect on the operating reliability of the Shell project. Similarly, potential problems with the related pipelines which would transport the Caroline NGL and condensate should not significantly affect the reliability of either project.

The Husky proposal would also involve sour gas transmission pipelines. However, the Board agrees with Husky that with dual pipelines in separate trenches, and with crossover lines at each line block valve site, a failure which would result in a stoppage of the flow of gas to Ram River would be unlikely and, if it occurred, would be of short duration. A transmission pipeline failure should not result in any sour gas flaring at Site E or Ram River.

6.3.3 Ram River Plant

The Board concurs with Husky that in the event of a shut-down of the Ram River plant, the Caroline gathering system gas could be displaced into the transmission pipelines and be recirculated. It is the Board's judgement that some flaring of sour gas would likely occur at Ram River in order for the transmission pipelines to accept all of the gathering system gas volume.

In addition to potential shut-down problems as noted above, the Board sees a potential for operating problems at the Ram River plant, particularly when compared to the Shell proposal, for the following reasons:

- Husky, unlike Shell, does not have experience with the use of SCOT technology,
- during start-up, the Ram River plant would have to carry out flow adjustments from up to 15 fields while the Shell plant would have inlet flow from only one field, and
- the Ram River plant would have a mix of new and used equipment, compared to all new equipment at Shell's plant, and would therefore be more likely to experience problems.

The Board would expect a new plant such as Shell's proposed facility to achieve a 99.8 per cent sulphur recovery level within the first 6 months of operation. In the case of the proposed plant expansion at Ram River, it is quite possible that Husky may not be able to consistently achieve such a recovery within the same time frame.

6.3.4 Conclusions Respecting Operating Reliability

In summary, the Board believes that both proposals would be acceptable in terms of operating reliability. Accordingly, the Board would not require additional redundancy in certain equipment at the Husky gas transmission plant as was suggested by CAB. In comparative terms, Shell would have an advantage in handling field compressor shut-downs whereas Husky would have an advantage in handling Site E plant shut-downs. However, Husky would also have to contend with possible Ram River plant failures. This, along with the potential problems associated with retrofitting the Ram River plant and the number of fields it would be serving, causes the Board to conclude that, with regard to operating reliability, Shell's proposal is somewhat better than Husky's.

The Board would require that if Husky is the successful proponent, its gas transmission plant design be reviewed to ensure it would be capable of maintaining the appropriate discharge pressure during field compressor shut-downs. This improvement would likely minimize or eliminate the potential for sour gas flaring in these situations.

7 RESOURCE CONSERVATION

7.1 Introduction

The Board believes that an important measure of orderly development is the degree of overall resource conservation achieved by a development. The aspects of resource conservation considered are ultimate reservoir recovery, field and plant energy consumption, and sulphur transport energy consumption. (The latter two aspects are also discussed in Section 8.2.2 with respect to CO_2 emissions.)

7.2 Reservoir Recovery

Husky suggested that its proposal, relative to the Shell proposal, would result in possibly 1 or 2 per cent more gas recovery from the Caroline reservoir because of improved economics. Shell did not expect any significant difference in ultimate recovery between the two projects.

The Board believes that processing Caroline production at the Ram River plant could result in some extension of the lives of reservoirs currently producing to that plant, by lowering operating costs per unit of throughput. (Section 12 includes a discussion of the potential for other new gas supplies.)

Ultimate recovery from the Caroline reservoir, and from the Bearberry reservoir if its production were to proceed on a commercial scale, would be determined largely by operating costs at the end of the lives of these two reservoirs. In this regard, the Board believes that the Shell project would have some advantages because of its proposed plant being closer to these fields.

On balance, the Board does not believe it is appropriate to attribute any advantage to either Shell or Husky regarding reservoir recovery.

7.3 Field and Plant Energy Consumption

Husky estimated that its incremental fuel gas consumption over present usage at Ram River, for gathering, transporting, and processing Caroline gas, would be 333×10^3 m^3/d, which is considerably less than Shell's estimated usage of 630×10^3 m^3/d. Husky claimed that this is due in large measure to its proposed use of oxygen-enrichment in its sulphur recovery facilities, which would result in the generation of additional process heat and in lesser volumes of inert gases being heated in the plant's incinerator. Husky's estimates showed that these fuel gas savings more than offset the energy required to produce the oxygen and to transport the Caroline gas from Site E to the Ram River plant. Overall, Husky's estimated total additional energy consumption, fuel gas and electric, is approximately two-thirds of Shell's.

The Board questions the large difference in estimated total energy consumption between the two proposals. It believes that a portion of the estimated difference may relate to improvements in efficiencies in the existing Ram River plant. Nevertheless, on the basis of the information available to the Board, there is a significant advantage to the Husky proposal. Due to the apparent large fuel saving with oxygen-enrichment, the Board would require Shell, if its proposal were approved, to carry out a further review of the energy efficiency, economics, and operational reliability of using oxygen-enrichment at the outset in the Caroline plant.

7.4 Sulphur Transportation

Shell stated that the transport distance of sulphur product from Shantz to Vancouver via CP would be 1168 km, as compared to 1624 km from Ram River to Vancouver via

CN under the Husky proposal. Shell contended that less energy would therefore be required for the CP route, although not necessarily in proportion to the difference in distances.

CN claimed that the longer distance of its route was offset by lower grades, to the extent that energy consumption would be within 1 or 2 per cent of the CP requirements. CN further suggested that if the proposed Shell plant were approved, there would be environmental and economic advantages to pipelining the liquid sulphur to the existing sulphur forming and loading facilities at the Ram River plant. CN recommended that the Board require an examination of this alternative.

In the Board's view, the evidence suggests that there may not be a significant difference between CN and CP fuel consumption and hence no clear advantage to either proposal. Regarding the suggestion that Shell's proposed Caroline liquid sulphur pipeline be routed to Ram River rather than to Shantz, the Board would not condition any Shell approval to require further assessment of the Ram River alternative, because the Shantz proposal was found to be acceptable and because CN's suggestion of the Ram River option was not strongly supported.

7.5 Conclusions Respecting Resource Conservation

The Board sees an advantage to the Husky project in having less overall energy consumption in plant operations, resulting from the use of oxygen-enrichment technology. The Board sees little difference between the projects in terms of ultimate reservoir recovery or sulphur transportation fuel.

8 ENVIRONMENTAL IMPACTS

8.1 Introduction

It has been clear since the discovery of the Caroline Beaverhill Lake gas reserves that the development of such a large and sulphur-rich gas reservoir must be conducted in a manner which would ensure that any impacts to the existing natural environment are mitigated (reduced) to the greatest extent possible. Furthermore, such a development should only proceed if the remaining (residual) negative impacts which cannot be mitigated are considered to be less than the offsetting economic and social benefits. The Board believes that if a proposed development is predicted to have significant residual negative environmental effects which cannot be effectively mitigated, then approval should be denied, since such a project would not be in the public interest.

The difficulty facing the Board in making this assessment is that a clear measure rarely exists regarding the acceptability of environmental impacts. For some impacts, such as atmospheric emis-sions, where there are existing environmental standards, an assessment of the relative accept-ability of a proposed development can be made on a quantitative basis. In other areas, for example, impacts on wildlife, such standards are not readily available.

The Board recognizes that Alberta Environment administers the EIA review process, and in that capacity makes decisions regarding the need and scope of that review, and also co-ordinates the analysis by other provincial government departments of the EIA. At the hearing, Alberta Environment asked that the Board specifically recognize the issue of gas plant emissions and their potential for regional impacts. Alberta Environment also stated that subsequent to the Board's decision, it would be in a position to consider the successful application with regard to the requirements of the Clean Air Act, Clean Water Act, Water Resources Act, and the Land Surface Conservation and Reclamation Act.

In making its assessment of the environmental acceptability of the two proposals, the Board has relied in part on the comments and questions raised by Alberta Environment respecting the EIAs submitted by the applicants. Additionally, both applicants and several interveners provided technical experts to respond to environmental questions. Finally, many of the interveners spoke directly to environmental matters. They provided the Board with further insight as to the value placed on protecting the natural environment, and as to the trade-offs between development and its associated economic benefits, and possible environmental changes which would be considered acceptable.

Both proponents made lengthy and detailed submissions on environmental matters. The primary biophysical issues which the Board has considered in this section are atmospheric emissions, surface and groundwater (quality and quantity), wildlife, fish, vegetation and soil. Other issues which impact more directly on the human environment, for example, public safety, noise and land use, have been addressed in Sections 9 and 10. However, the Board recognizes the intrinsic inter-relationship between human and environmental well-being and has endeavoured to fully address these issues throughout the report.

8.2 Atmospheric Emissions

There is little question that atmospheric emissions represent the largest potential source of regional impact from a sour gas development, especially if the development is large and has a relatively high H_2S content.

The impacts of any new development in the Caroline region cannot be assessed in isolation, since the area already contains a number of sour gas processing facilities. Therefore, it is important that incremental impacts on regional air quality be assessed.

In evaluating the impacts of atmospheric emissions on regional air quality, the Board has considered three main contaminant sources. These are SO_2, which results from the combustion (incineration) of the small amounts of H_2S which are not removed during processing of the gas and CO_2 and oxides of nitrogen (NO_x), both of which are produced during the combustion of fuels such as natural gas, diesel, and coal. The Board recognizes that there were concerns expressed regarding other possible contaminants such as heavy metals; however, no evidence was presented that these would create significant problems. Additionally, tests conducted at other sour gas plants in Alberta have not indicated that these other contaminants represent an environmental risk.

Fugitive emissions of H_2S, various mercaptans, and volatile hydrocarbons, which can be released from a number of sources in small, but odorous volumes, are addressed in Section 10.2.4. Impacts from localized emissions due to flaring and sulphur block fires are examined in Section 8.7.

8.2.1 Sulphur Dioxide (SO_2)

The Board has required for many years that, where sulphur inlet rates are sufficient to warrant, the plant operator must recover a set minimum amount of elemental sulphur, based on a percentage of the total sulphur inlet. As discussed in Section 6, the Board believes that 99.8 per cent recovery is achievable with the technology proposed by either applicant. The Board will require a 99.8 per cent annual average recovery with a minimum quarterly recovery of 99.5 per cent. The remaining 0.2 per cent of sulphur, which would not be recovered, would be incinerated at the plant and emitted to the atmosphere as gaseous SO_2. Therefore, even if the sulphur recovery levels are met, it is recognized that some SO_2 would be emitted into the atmosphere and would result in SO_2 levels in the ambient air.

Standards and Guidelines

Ambient SO_2 levels in the atmosphere are routinely monitored on a continuous basis at sulphur recovery plants in Alberta. Current Alberta maximum permissible ambient air levels for annual, daily, and hourly SO_2 concentrations are:

Annual	10	parts per billion (ppb) (0.01 ppm)
Daily	60	ppb (0.06 ppm)
Hourly	170	ppb (0.17 ppm)

These correspond to the strictest of three Federal standards. The 0.17-ppm 1-hour standard is enforced at tree-top level in forested areas and at ground level in open areas.

Static monitoring of sulphur deposition rates is also required by Alberta Environment. This is done using a network of exposure cylinders which the operator is required to maintain in the vicinity of the plant. The Alberta guideline for total sulphation exposure is 0.50 milligrams of sulphur trioxide (SO_3) equivalent per day per 100 square centimetres (mg/d/100 cm^2 of SO_3 equivalent). The guideline for H_2S exposure is 0.10 mg/d/100 cm^2 of SO_3 equivalent.

At the hearing it was pointed out that different types of exposure cylinders, which were not directly comparable, were being used in the Caroline region. The Board intends to review this matter with Alberta Environment.

As mentioned previously, the sulphur compounds emitted from the plant will be in

the form of gaseous SO_2. Once in the atmosphere, gaseous SO_2 can be oxidized into a sulphate SO_4^{-2} particulate. These compounds are removed from the atmosphere by wet and dry deposition mechanisms. Dry deposition involves the direct accumulation of these compounds on the surface of vegetation or soil, while with wet deposition, the compounds are first trapped in rain or snow.

Presently, no standards for acceptable levels of sulphate deposition have been established in Alberta. Research in this area is currently under way to establish either sulphate or effective total acidity targets and this was discussed by both applicants and the RVC. The Board is actively monitoring this research and will consider how to best apply the eventual results. In the interim, the Board believes that it can only regard as preliminary the target loading values which were discussed at the hearing. In the Board's view the specific targets should not be used to judge the acceptability of either proposal although the matter of sulphate deposition is important. The Board intends to continue to work with industry, the public, and the government to ensure that appropriate standards are adopted.

Existing Measured Regional Sulphur Levels

Both applicants used existing monitoring data from regional gas plants as a source of current area SO_2 levels and sulphur deposition rates. Additionally, the recent Acid Deposition Research Program (ADRP) provided a measure of regional sulphate deposition.

The regional SO_2 levels were generally within the current Alberta standards, with the exception of occasional exceedances of the hourly SO_2 standards at monitoring stations in the region.

Both applicants indicated that present regional sulphur deposition rates were well below current guidelines. The maximum values measured using static monitors were 0.16 and 0.008 mg/d/100 cm^2 of SO_3 equivalent for total sulphation and H_2S, respectively.

The ADRP estimated that sulphate deposition in the Caroline and Ram River region was 20 to 50 kilograms per hectare per year (kg/ha/yr) which includes a background of 10.8 kg/ha.

Predicted Regional Sulphur Levels

Both applicants made extensive use of computer models to estimate worst case SO_2 concentrations at various distances from their proposed facilities. The models take into account a number of factors including stack height and diameter, exit temperature and velocity, local terrain and vegetation, and regional meteorological conditions. Shell and Husky also made use of data from the existing SO_2 sources in the region to evaluate their modelling results.

The Board recognizes the need for and the importance of atmospheric modelling and believes that the models selected by the applicants provided indications of trends and gave reasonable estimates of maximums. The Board also accepts and understands their limitations. For this reason, any approval granted by the Board based on modelling predictions will require monitoring to determine actual measured SO_2 concentrations. If exceedances were to occur, further modifications to the plant design and/or operations would be necessary.

Both applicants provided historical data on regional sources of SO_2 and used them as a basis for modelling the anticipated impacts of the two proposals on regional SO_2 concentrations and sulphur deposition. The most up-to-date data was provided by Husky as follows:

	SO_2 Emissions (t/d) 1988
Husky Ram River	53.5
Gulf Strachan	12.2
Mobil Harmattan	5.6
Amoco South Caroline	1.8
Amoco North Caroline	1.8
Altana Caroline	4.1
Home Harmattan-Elkton	1.6

In its submission, Shell assumed that the actual 1987 emission levels at all plants including the Ram River plant would remain at current levels, with the exception of the Altana plant. The Altana plant would be reduced to zero, while the Shell Caroline plant would emit an additional 16.3 t/d of SO_2 to the regional airshed. In the Husky submission, the actual 1988 Ram River emission level of 53.5 t/d of SO_2 would be reduced to 27.2 t/d, although a slight upward revision of this number would be necessary if Altana's acid gas was processed at Ram River.

Neither applicant included the SO_2 emissions expected from the Shell Burnt Timber plant or existing or future foothills gas discoveries in their models. One of the interveners suggested that the likely emissions from some of these reserves should have been included. The Board agrees with Shell that the Burnt Timber gas plant would likely have no significant impact on the Caroline region because of levels of emissions and intervening distances. The Board would require additional assessments of any future regional reserves of either significant size or H_2S content before permitting them to be processed.

Both applicants presented results from modelling scenarios generated using the Alberta Environment model, STACKS2 to generate hourly SO_2 averages, and ADEPT to calculate annual SO_2 averages and annual sulphate equivalent deposition. Furthermore, both applicants, in part at the direction of Alberta Environment, provided the results of several other modelling approaches. These approaches provided further insight regarding the effect of certain topographical features and seasonal variations. The Board does not intend to comment on the relative merits of the various approaches used, but does acknowledge the extensive work done by both applicants. The Board also found the meteorological data base from Ram River to be valuable and will require the successful applicant, as suggested by BLCOA and others, to gather these types of data. Additionally, the Board found that the use of several modelling approaches provided a reasonable approximation of the range of error which could be associated with a particular modelling approach.

Although the models provided a range of predictions, the Board has been able to draw certain conclusions. First, none of the studies predicted any significant exceedances of current annual SO_2 standards. With respect to daily and hourly SO_2 standards, under the Shell proposal, some exceedances are predicted near the proposed Shell plant under extreme case conditions. A similar situation was predicted for various Husky scenarios. In the first case, the modelling also assumed that the Husky Ram River plant operated at its currently licensed maximum SO_2 emission rate of 177 t/d. At these levels, frequent exceedances of the current hourly and daily SO_2 guidelines are predicted to occur at several locations in the vicinity of the Ram River plant. The risk of such exceedances declined significantly using that plant's recent actual annual average SO_2 emission rate of 53.5 t/d but some exceedances were still predicted. Under the Husky proposal, because the annual average emission rate would be 27.2 t/d at Ram River, the predicted frequency of exceedances is even less. Therefore, in terms of maintaining regional SO_2 air quality

standards, Husky's proposal has an advantage over Shell's.

With respect to sulphate deposition, the Board notes that only for fully licensed conditions, the model predicts deposition rates greater than 50 kg/ha/yr in some limited locations. The Board also notes that current estimated deposition levels are in the range of 20 to 50 kg/ha/yr, and because of declining reserves of high sulphur content gas, will likely be further reduced under either scenario. Based on the predictions made by both applicants, the Board finds that either proposal would likely have an acceptable sulphate deposition level. The Husky proposal does, however, represent a reduction in regional sulphur emissions. The Board can only comment that it is concerned about regional deposition levels under any development scenario, and will continue to work with Alberta Environment in the development of regional depositional standards.

The potential advantage of the Husky proposal with respect to regional sulphur emissions is further demonstrated by estimating lifetime SO_2 emissions under various scenarios. Under the Shell proposal, a total of some 212 000 t of SO_2 would be emitted over the duration of the projects from the combined emissions of the proposed Shell Caroline and existing Husky Ram River gas plants. This compares to an emission level of about 115 000 t of SO_2 under the Husky proposal, or a difference of some 97 000 t. The actual environmental impact of such a reduction is unknown, but is likely to be positive.

Existing Ram River Plant Operations

Both CAB and Shell raised an issue regarding the complex terrain in the vicinity of the Ram River plant particularly in relation to Baseline Mountain. They argued that the complex local topography created a downwash which subsequently resulted in SO_2 exceedances at Baseline Mountain. A detailed meteorological explanation of the downwash and required "*mountain to plant*" distance was provided by Husky. While the Board accepts Husky's claim that the plant should be far enough away from Baseline Mountain that downwash would not typically occur, there still remains a past history of more exceedances at Baseline Mountain than elsewhere. Data indicates that since 1971 there has been a significant number of exceedances at Baseline Mountain. Husky contended that this is operationally created as opposed to being due to undesirable atmospheric conditions. The Board believes that if certain operational aspects are creating these exceedances, they must be addressed by Husky whether or not it receives approval respecting the Caroline gas.

Conclusions Respecting Sulphur Emissions

Under either proposal, the facilities processing the Caroline gas would achieve an annual average sulphur recovery level of 99.8 per cent, as prescribed by the sulphur recovery requirements. In terms of overall regional sulphur emissions, Husky's proposal has an advantage with respect to reducing expected exceedances of annual, daily, and hourly SO_2 concentration standards and also regarding lifetime emissions.

Whichever project proceeds, the Board expects that Alberta Environment will prescribe proper monitoring requirements. Detailed baseline studies and monitoring were requested by a number of participants, including CAB, PALSS, and RVC. These requests related not only to SO_2, but also to heavy metals, ozone, and other compounds. They also dealt with the amount of monitoring required and locations of monitoring stations. The Board agrees that special monitoring is necessary, intends to ensure that Alberta Environment is aware of all requests, and will work with the

department in that regard. In accordance with recommendations from several participants, monitoring results will be made public. (Further information regarding monitoring is included in Section 8.7.)

8.2.2 Carbon Dioxide (CO_2)

Shell estimated that its proposal for gathering and processing the Caroline reserves would release 3240 t/d of CO_2 to the atmosphere. Of this amount, 2130 t/d would be released at the plant site, made up of CO_2 emitted from gas-fired equipment including the sulphur plant tail gas incinerator and the CO_2 contained in the raw gas which is released during processing. Shell stated that fuel gas used at its plant, and therefore CO_2 emissions, would be reduced by maximizing the use of sulphur plant steam to power the steam turbine drivers and so reduce the utility boiler steam requirement. Shell also stated it would be using a fuel-efficient, forced draft incinerator at its plant.

Fuel gas combustion at field facilities such as line heaters would result in 120 t/d of CO_2 emissions throughout the field.

Shell estimated that electrical power used at the gas plant and field facilities and produced at coal-fired power plants in Alberta would generate an additional 990 t/d of CO_2. Shell suggested that its proposed rail transportation of sulphur product from the Shantz terminal to the west coast would result in less fuel consumption and therefore less CO_2 emissions than Husky's proposal because of the shorter distance involved.

Shell also stated that CO_2 produced at its proposed Caroline facilities could be recovered for use in an expansion of an existing CO_2-flood enhanced oil recovery (EOR) scheme at Harmattan. Shell noted, however, that a decision to expand the Harmattan EOR scheme would be based more on the economic and technical feasibility of the scheme than on possible environmental benefits of reducing CO_2 emissions.

Husky estimated that gathering and transporting the Caroline gas to its Ram River plant and processing it there would produce 3314 t/d of CO_2. Of this, 1306 t/d would be produced at Husky's Ram River plant, most of which would be CO_2 received at the plant in the Caroline raw gas and released during processing. Husky noted that its proposed sulphur plant retrofit using oxygen-enrichment technology would result in considerable fuel gas savings relative to Shell's proposal because of the smaller sulphur plant tail gas volume being incinerated and because of the increased sulphur plant steam. This would result in the amount of CO_2 produced from fuel gas combustion at Husky's plant being less than 20 per cent of the amount estimated by Shell for its proposed plant.

Husky stated that the Meteorological Controlled Emission System (MCES) on its incinerator stack results in incinerator fuel savings by reducing the stack-top temperature whenever atmospheric conditions are such that satisfactory plume dispersion would continue even with the reduced temperature. Additionally, Husky stated that waste heat would be recovered from all turbine compressor units to further reduce fuel gas consumption and therefore CO_2.

Husky indicated that fuel gas consumption at its proposed field facilities, including its Caroline gas transmission plant, would produce 418 t/d of CO_2. Husky estimated that its electrical power requirements for its expanded Ram River plant, field facilities, transmission plant at Site E, and the proposed air separation plant would result in the production of 1590 t/d of CO_2 at the source thermal power generating plant. With respect to the electrical power requirement of the air

separation plant, Husky noted that CO_2 emissions could be reduced by 238 t/d if the electricity was generated using gas turbines at its Ram River site.

Husky disputed Shell's claim that sulphur transportation from the Shantz terminal would be significantly more fuel efficient than Husky's proposed transportation from the Ram River plant. Husky stated that although Shell's proposed transportation would be over a shorter route, the difference in grades between Shell's route and Husky's is such that fuel consumption, and therefore CO_2 emissions, would not be significantly different. CN said the two routes would be within 2 per cent of each other.

Conclusions Respecting CO_2 Emissions

The Board has considered the information submitted by Shell and Husky regarding CO_2 emissions from their respective proposals. The Board concludes that, although the projects have differences in terms of distribution of the total amounts of CO_2 between field facilities, the processing plant sites, and electrical power generating stations, the total amount of CO_2 emissions from either project would be similar. The most significant difference between the two proposals would be due to Husky's reduced fuel gas consumption at its Ram River plant made possible by the oxygen-enrichment technology. This advantage in terms of CO_2 emissions is offset, however, by the increase in CO_2 emissions due to the electrical power requirement of Husky's air separation plant and gas transmission plant.

The Board is satisfied that both proposals contain reasonable design measures to limit CO_2 emissions, and are therefore acceptable in this regard. There is very little difference between the projects in terms of total emissions. The Board notes that a significant portion of the CO_2 that would be emitted by either scheme, some 35 per cent, is a function of the reservoir gas composition and is independent of energy conservation measures.

The Board recognizes the increasing concern about CO_2 emissions to the atmosphere and their possible relationship to global climatic change. Some interveners suggested that a carbon tax on CO_2 emitted to the atmosphere should be imposed to encourage energy conservation, and possibly the disposal of CO_2 to underground formations as an alternative to venting the gas to the atmosphere. The Board is aware that the Alberta Government is involved in studies on CO_2 issues and expects that such suggestions will be considered in developing a policy for the province.

The Board notes Shell's evidence that a possible use for Caroline CO_2 could result from expansion of the existing Harmattan EOR scheme. The Board agrees with Shell that while some environmental benefit could be derived, any decision to expand Shell's Harmattan scheme would need to be based largely on the technical and economic feasibility of that scheme itself.

8.2.3 Oxides of Nitrogen (NO_x)

Shell estimated that the total NO_x emission rate from its Caroline project would be 3 to 4 t/d. This would be emitted from gas-fired equipment such as heaters and flare pilots. Although the final design of its fired equipment has not yet been completed, Shell stated that it would be using low-NO_x burners and all stacks would be designed to comply with Alberta Environment's standards for ground-level NO_x concentrations. These standards are 0.03 ppm for an annual average, 0.11 ppm for a daily average, and 0.21 ppm for an hourly average.

Shell proposed to use electric drivers on its field compressors to eliminate NO_x emissions from that source. Shell's estimate included NO_x emitted at the source electric power generating station for the project's electrical requirements.

In response to questioning, Shell stated that it would not expect any increase in NO_x emissions if the Bearberry reserves were integrated with its Caroline project.

Husky estimated that its proposal to process Caroline gas would generate a total of 6.25 t/d of NO_x. Of this amount, 1.81 t/d would occur at the Ram River plant, 0.3 t/d would occur at the Site E gas transmission plant and transmission pipelines, and 4.14 t/d would occur at the site generating electrical power to meet the project's requirements. NO_x sources at Husky's plants and on the transmission system would include gas-fired boilers, reboilers, and heaters.

The Board has reviewed Shell's and Husky's evidence respecting NO_x emissions and has concluded that Shell's proposal appears to have a slight advantage in terms of lower NO_x emissions. The Board is also of the view that both proposals would employ adequate measures to minimize NO_x emissions and would comply with Alberta Environment Clean Air standards.

8.3 Surface Water

There is an obvious interrelationship between surface water, dealt with in this section, and groundwater, dealt with in the next section. Notwithstanding that some degree of overlap results, the Board believes they are each important enough to be addressed separately.

Within each project study area, surface water quality data has been collected to characterize the surface water resources that may be affected. Water in the regional area can be characterized by:

- A high pH, except for muskeg areas.
- Adequate dissolved oxygen levels, except for muskeg areas.
- High calcium, magnesium, and bicarbonate levels.
- Low sulphate levels with the exception of natural sulphur springs and two small creeks which currently receive treated runoff water from the Ram River plant.
- Low total suspended solids except for high flow periods.

For the Shell Site E gas plant, a supply of fresh water would be required to augment the recycled water obtained from the processing, sewage treatment, and storm water volumes. This additional requirement would be supplied by new source water wells placed to withdraw water from the Red Deer River. The supplemental water required would average 100 m^3/h and range from 50 m^3/h to an expected maximum of 150 m^3/h. Based on existing stream flow in the Red Deer River, Shell concluded that sufficient water would be available at this withdrawal level to meet all other current user demands. Domestic water for the construction camps would be supplied by two wells which would tap the James River. The Shantz sulphur forming facilities would also require an average of 13 m^3/h for process cooling and would be drawn from the Harmattan reservoir which draws water from the Little Red Deer River during periods of high runoff. Shell has applied for the required permits and licences from Alberta Environment for these water withdrawal volumes.

Shell stated it would operate its proposed Site E plant as a Class B gas plant which, in accordance with Alberta Environment's regulations, would not permit the discharge of process water to a watercourse, groundwater, or the surrounding watershed. Shell

committed to avoid releasing any other fluids or effluents to surface water or the surrounding watershed area from either the Shantz facilities or the Caroline gas plant. Waste streams from the plant would be directed to deep disposal wells, although application for injection into these wells had not yet been filed by Shell. Sanitary waste water would be treated in an on-site facility and re-used, and Shell said that discharge to a surface water course would not be required under normal plant operations. Shell noted its proposed Site E plant would present a low risk of surface water contamination as there are no water bodies in the immediate vicinity.

With regard to the Husky proposal, five local groundwater wells currently supply water for industrial purposes at the Ram River plant. Husky estimated that an additional 50 m^3/d of water would be needed for domestic and utility use, which could be obtained from the existing wells. Under the expansion proposal, additional water supplies would be obtained from the Clearwater River and pipelined 21 km to the Ram River plant. The fresh water pipeline would provide a maximum of 150 m^3/h of water for process cooling, although Husky claimed that, on average, only 30 m^3/h of water may be required. Husky said water withdrawal permits have not been applied for at this time pending further field investigations.

At Husky's proposed Site E gas transmission plant, raw water would be required for domestic, fire control, and utility use and these volumes would be obtained from wells to be drilled at or near the facility. Husky estimated its water requirement to be 0.5 m^3/h on a continuous basis. Husky said it did not anticipate encountering any produced sour water at its Site E gas transmission plant until the field pressures declined substantially.

Husky stated that its expanded Ram River gas plant would be operated as a Class B facility under Alberta Environment's regulations, and thus no release of process water to a surface water body would be allowed. All process waste water and produced water would be disposed of by deep well injection. Husky said it would continue to release sewage to septic fields and the lagoon. Surface run off water would continue to be tested, treated, and released to Loadout and Flare Creeks.

Experts for Husky, Shell, and several interveners generally agreed that surface waters in the study area have good buffering capacity and no problems due to possible acidification from airborne emissions are anticipated.

During the hearing, evidence was presented regarding the impacts of the existing Ram River plant operations on local surface water quality. The sulphur dust problem at Ram River and the corrective liming program has resulted in increased levels of calcium and sulphate ions (Ca^{++} and SO_4^{-2}) in streams adjacent to the facility, though pH has remained unaffected. The release of treated runoff water is likely the greatest source of the elevated conductivity values which are also observed. The discharge of contaminated groundwater may also contribute to this situation. Husky stated it recognized these problems and they would be addressed. Husky also suggested that there would be no incremental impact due to the addition of the Caroline gas reserves to its Ram River plant. However, Shell claimed the existing environmental problems at Ram River are not fully defined and could be very difficult to address. Shell stated that it did not want to assume those potential mitigation costs in order to process its Caroline gas.

The Board believes that each applicant has the desire and capability to transport and process the Caroline gas reserves with minimum impact on the fresh water resources in the region. Neither proposal appears to present an

unacceptable risk in this regard, and no significant difference between the proposals is evident. The Board has concerns regarding the local creeks that are affected by the current Ram River operations and agrees with several interveners that regardless of the outcome of the Caroline development, the problem must be mitigated. The Board accepts Husky's commitment that the problems would be rectified. The Board will monitor the situation and, along with Alberta Environment, review alternative disposal options, including the use of deep well disposal for all waste waters, including surface run-off rather than surface release.

8.4 Groundwater

The Board places a high priority on ensuring groundwater quality is protected during the development of oil and gas resources. In assessing the relative merits of the two proposals, the Board took into account differences in the possible risk of future groundwater contamination at the proposed sites for the plants and other facilities, as well as the implications of any existing groundwater contamination.

With regard to the latter issue, concern was raised by some of the Caroline Owners as to their potential liability for the existing groundwater contamination at Husky's Ram River plant site. The Board notes that groundwater contamination has occurred at Ram River from two sources, a condensate leak in the late 1970s and sulphur block run-off, both of which were identified by Husky in its application. The Board also notes that during the hearing, Husky made a commitment to resolve these problems whether or not Caroline gas is processed at the Ram River plant. Notwithstanding the commitment, the Board believes that the existing groundwater contamination at the Ram River plant would likely complicate the necessary commercial arrangements between Owners and the current plant owners if the Caroline gas should be processed at Ram River.

Shell indicated at the hearing that groundwater contamination has occurred at Mobil's Harmattan gas plant, and Shell's proposed Shantz sulphur forming facilities would be adjacent to Mobil's plant. Therefore, the Board must address the issue of possible incremental groundwater impacts arising from the development of either proposal.

Groundwater contamination could occur from several sources including the spillage of process fluids and liquid hydrocarbon product, leakage from ponds used to temporarily hold contaminated water, runoff from sulphur block storage areas, and from sulphur dusting.

In both proposals, condensate would be removed at Site E and pipelined to Amoco's Sundre terminal. The Board is satisfied that a key criterion used by both firms in selecting Site E was its relative suitability to contain any spills, including condensate. The Board also accepts both Shell's and Husky's plans to continue to monitor and ensure that no groundwater contamination from waste water storage ponds at Site E would occur. Therefore, no significant differences between the two proposals appear to exist on these issues.

With regard to sulphur storage, significant differences do exist between the two projects. Husky's proposal, which would have a maximum sulphur inlet rate of 6800 t/d, has the potential to increase the sulphur storage area at the Ram River plant site. Unlike Site E, the Ram River plant site has less native ability to prevent further groundwater contamination and has a relatively complex groundwater regime. Therefore, some increased risk of added groundwater contamination from sulphur block runoff appears to exist at this site. This risk is further compounded to an unknown degree by

the existing groundwater problems, and by the on-going problems with sulphur dusting from Husky's sulphur forming facilities.

In Shell's case, any storage of sulphur would occur at Shantz, where hydrogeological investigations are as yet incomplete. Early indications suggest that, from a groundwater perspective, stringent controls regarding base pad design including impervious barriers in the sulphur storage and handling areas would be a necessary mitigative measure. The Board believes that sulphur handling facilities can be developed, through proper engineering and design, in such a way as to ensure there is little risk to groundwater. Shell has committed to only pour sulphur to block on an emergency basis, to pave sulphur handling areas, to line with impervious materials any sulphur storage facilities, and to use other Shell sulphur storage facilities throughout Alberta, if necess-ary, to ensure that use of solid sulphur storage at Shantz is minimized. Furthermore, the low dust production levels from the proposed Shell Rotoforming facility should have little, if any, impact on the groundwater at Shantz.

In summary, the Board believes that with regard to groundwater issues, the Shell proposal has an advantage. However, the Board also notes that local hydrogeology at Shantz has not yet been thoroughly assessed by Shell and that the site is much closer to active domestic water wells than the Ram River plant. Therefore if the Shell project were approved, significant additional site investigation and stringent mitigative measures would be required to ensure that local groundwater contamination would not occur at Shantz.

8.5 Wildlife

A development the size of the Caroline gas reservoir has the potential to adversely affect a significant amount of wildlife habitat, regardless of which configuration is adopted for transporting and processing the gas reserves. Therefore, the degree to which wildlife species in the project area may be affected has been considered by the Board as one component of its evaluation of the two proposals.

Shell stated its project area has not been studied in depth with respect to wildlife populations, but by avoiding critical wildlife habitat and implementing extensive mitigation measures, potential impacts on wildlife would be decreased significantly. Shell committed to an overall net increase in wildlife habitat and to monitoring the effectiveness of the habitat enhancement measures that would be put in place, but did not provide details on how this would be achieved.

Shell stated that the Site E gas plant would occupy 60 ha of high-quality moose habitat. The liquid sulphur pipeline to Shantz would disturb another 9 ha of excellent moose habitat and would cross three areas of key wildlife habitat at the riparian (river bank) areas of the James, Red Deer, and Little Red Deer Rivers. This key wildlife habitat would be altered to the width of the pipeline ROW. Reclamation pro-grams would be designed to ensure revegeta-tion of these areas primarily to grasses, and for some wildlife species this would result in an increase in forage quantity and quality.

Husky would also locate its proposed gas transmission plant at Site E, but its smaller site would only disturb approximately 10 ha of high quality moose habitat. A further 123 ha of forested land of variable wildlife quality would be disturbed during construction of Husky's sour gas transmission pipelines. Approximately 30 per cent of this would be through relatively undisturbed areas, while the remainder would parallel existing linear developments. Along the length of ROW,

about 4.5 ha of critical wildlife protection zones would be altered, and some key wildlife habitat would be disturbed. Husky stated that construction and operation of its proposed pipelines is acceptable through these zones with appropriate reclamation, maintenance, and control of public access. It suggested that enhancement of existing habitat could be performed in areas off the immediate pipeline ROW. Husky said it is willing to work with local wildlife officials to attain a "*no net loss of habitat*" policy, but also provided limited information on how this policy would be achieved.

CRAG's experts supported the proponents' view that comprehensive baseline data for wildlife in the region was lacking. Although this criticism was directed primarily to the Shell proposal, the Board believes that several of the points raised could be equally directed towards the Husky proposal. The Board agrees that regional wildlife population and movement information is not readily available in published literature but recognizes the applicants' efforts to compensate by analysing habitat information. The Board accepts this alternative approach but believes that long-term baseline studies of wildlife species should be initiated as soon as possible, as part of the impact audit and mitigation process. CRAG's wildlife expert said he could not comment on the relative merits of the two proposals since he was not asked to study the impact of the Husky project.

In mitigating their respective wildlife impacts, both applicants committed to a "*no net loss of habitat*" policy. This was in keeping with recommendations from several interveners, including the Fish and Game Association. While the Board considers this to be a worthwhile objective, it questions how such a goal would be reached. For example, the creation of habitat with early successional stages of vegetation cover, such as grasses, may be beneficial to some wildlife species, but for others dependent on more mature or later successional habitat types, restoration of its habitat is intrinsically more difficult. Furthermore, neither company was able to indicate how its policy would address the issue of fragmentation of existing habitat by linear developments and other clearing. This is an issue of increasing concern to the Board, and one which the Board expects the industry to address in future.

The Board is confident that either applicant would work with the appropriate government agencies to reduce the impacts on wildlife species and habitat. The Board would require that the "*no net loss*" policy committed to by both applicants be adhered to in all aspects by the successful applicant. It would also require the successful applicant to evaluate and report on the success it has realized in implementing the policy.

In terms of actual wildlife habitat disturbed, the Shell proposal appears to have a slight advantage. The disturbance of land by Shell would include a significant amount of land already disturbed by agricultural development as compared to the relatively pristine forested areas that would be crossed by Husky's transmission pipelines. However, this advantage is reduced by the relatively larger amount of habitat area required by the Shell gas plant site, since this portion would not be available to wildlife over the life of the project.

A second key aspect of the impact of the proposed developments on wildlife is the increased access that would be created. A number of hearing participants referred to this problem and the likelihood of increased legal and illegal hunting, and the Board agrees that efforts must be made to properly control access. Both applicants cited certain mitigative measures which would screen the ROW access points from the public view or

restrict travel on the ROWs. Locations where access could be gained would be kept to a minimum. There remains some doubt as to the overall effectiveness of such proposals, particularly on Crown land or in previously undisturbed areas. The Shell proposal appears to have a slight advantage over Husky's, insofar as more of its facilities would be on private land where access would potentially be more easily controlled.

In terms of overall impact on wildlife, the Board believes that either project would be acceptable, but that special efforts and co-ordination with government departments will be necessary to accomplish the "*no net loss of habitat*" commitments made at the hearing. The Board does see a slight advantage for the Shell project in that less forested area would be disturbed and, if necessary, control of access would be easier to achieve.

8.6 Fish

The components of each project most likely to affect fish and fish habitat are the gas gathering lines, sour gas transmission pipelines and the liquid sulphur pipeline, and both proposals would involve stream crossings. The Board considers the potential for direct impacts to fish to include over-harvesting due to increased access, physical damage to fish habitat during in-stream construction, and inadequate restoration of riparian areas.

The issue of over-harvesting due to increased public access along pipeline ROWs into previously remote areas was raised during the hearing. Both applicants committed to making ROW access points difficult to enter and to see, and said that further site-specific precautions would be implemented during the operations phase.

Shell's gathering system and liquid sulphur pipeline would traverse primarily private lands. Therefore, it is possible that public travel would be restricted by landowners along these lines. No such control is possible on the Crown lands through which the Husky transmission pipelines would be constructed. The presence of Husky's construction camps at Ram River and Ricinus may also place short-term fishing pressure on relatively remote area streams. The need by Husky to develop new access points along the proposed transmission pipelines to service the ESD valves represents a further long-term risk for increased access and associated over-harvesting.

Also of significance to protecting fish and fish habitat is the number of stream crossings and the manner in which construction and reclamation would be carried out at each crossing. The Shell liquid sulphur pipeline from Site E to Shantz would involve crossing three relatively substantial rivers. It appears that none of the crossings should present major technical difficulties, but detailed engineering designs were not provided in the Shell applications or at the hearing.

Husky's sour gas transmission pipelines would require eight stream crossings, but of these only the Clearwater River appears to be comparatively broad, with braided channels. Husky was able to provide somewhat more information on the technical components of its proposed crossings than did Shell. Both applicants have agreed to work with Alberta Fish and Wildlife to mitigate the impacts of their project activity, and to enhance other fish habitat, resulting in a net habitat gain. Neither proponent indicated how habitat enhancement would be accomplished.

Evidence provided by CRAG suggested that along with the number of crossings, other features such as stream gradient should be considered in assessing relative impacts. The Board concurs with this, and notes that in general the crossings required by Husky would be less difficult than Shell's.

The Board believes that pipeline construction across flowing streams in the area could be accomplished with minimal disturbance to fish habitat and no major long-term effects. Either project is therefore acceptable, although the Board recognizes that a detailed program of stream reclamation and inspection would be required. Further, the Board would require the successful applicant to honour its commitment to "*no net loss*" of fish habitat, and to provide evidence of the eventual success of its program.

Overall, Shell may have slightly more indirect control over increased public access to streams and has fewer crossings. Husky appears to have fewer difficult crossings and to date, has produced a more detailed evaluation of them. Recognizing the extensive experience of the two applicants in managing pipeline construction, neither proposal has a clear advantage over the other in this area of concern.

8.7 Vegetation

The Caroline hearing involved extensive discussion of the atmospheric emissions involved for each proposal. Each applicant presented considerable evidence to support its emission predictions, and the Board's evaluation of the scenarios is discussed in Section 8.2.

The proposals of both Husky and Shell acknowledge that there are already significant, albeit declining, SO_2 emissions from existing sour gas processing plants in the broad region, and that development of the Caroline reserves would, without remedial work at existing plants, add to that total SO_2 load.

The specific issue of vegetation damage from atmospheric emissions was raised primarily by the intervention of the RVC. The intervention, though ultimately indicating support for the Husky proposal, presented testimony by its expert, Mr. Bouman, who stated that damage to forest vegetation was already evident in the vicinity of the existing Ram River plant. RVC claimed that a general deterioration of the local forests around the Ram River plant site was observable over the last few years, and this decline would continue given the types of emissions and chemistry of the soil in the forest areas adjacent to the Ram River gas plant. The RVC stated that the Board should use the opportunity presented by development of the Caroline gas reservoir to reduce regional SO_2 emissions by approving Husky's project.

Shell provided no direct evidence on the issue of regional vegetation damage other than to note that its proposal would reduce local sulphur deposition by recovering the sulphur from Altana's currently flared acid gas. Shell added its sulphur handling program would produce a minimal amount of sulphur dust and therefore would have no associated impacts on vegetation.

To refute the RVC claims that the forest was already being harmed by gas plant emissions, Husky provided its own soil and vegetation monitoring data collected in the area of its Ram River gas plant. Husky also referenced Forestry Canada studies that it believes support its conclusion that past and current levels of SO_2 emissions have had little or no measurable effect on regional soils and vegetation, other than in those areas under the direct influence of sulphur dust.

Husky acknowledged that sulphur dust and SO_2 fumigation during sulphur block fires have had an extensive negative effect on forest vegetation immediately adjacent to the Ram River plant. The area of detectable sulphur dust accumulation around the Ram River facilities is about 1700 ha and death of vegetation in the immediate plant vicinity has

occurred due directly to either dust or SO_2 fumigations during sulphur block fires. Soil liming programs in highly contaminated areas have been used to reduce the effect of elemental sulphur on vegetation and soil. Under the Husky proposal, it appears likely that significant sulphur dusting will continue, and possibly that the life of the sulphur block, and therefore risk of sulphur block fires, would be extended by the increase of sulphur throughput at the plant.

Husky does not believe forest damage is evident beyond the sulphur dusted areas from any gas plant emission related cause. For example, Husky noted that since 1971 it had commissioned a bio-monitoring program in the region through the use of pollution sensitive lichens. Except for some changes in the lichen population, attributed again to sulphur dust problems, species numbers and frequency data indicated that no acute or chronic damage to vegetation has occurred. Husky maintained that it did not expect any future damage to vegetation would occur since emission rates, under its Ram River plant expansion proposal, would be much lower than past levels.

At Husky's request, Forestry Canada also provided evidence to support the claim that no regional forest damage from SO_2 emissions is evident. Forestry Canada scientists stated that their research in the Ram River plant area indicated no obvious effect on trees from gas plant emissions. Their study did suggest that some trees in the region were under stress from a number of factors including disease and climatic effects, due in part to the relatively old age of some stands, and this has resulted in visible tree damage and death. Other, younger stands not influenced by external activities such as road building, were in good condition. Forestry Canada emphasized that adequate knowledge of the ecology of a suspect area is required, as well as information on climatic conditions, soil nutrient deficiencies, and insect and disease disorders in the area, in order to distinguish between the many sources of vegetation damage.

Mr. Bouman, on behalf of RVC, explained his concept of the biochemical reactions occurring in the soil and vegetation, and he also presented visual evidence of tree damage purported to be due to SO_2 emissions. Based on his observations, he prepared a report describing several stands of coniferous trees that had allegedly been damaged or stressed by atmospheric emissions. The RVC submission discounted Husky's bio-monitoring data, claiming that the surviving lichen species are SO_2 resistant. The RVC claimed that the situation is deteriorating in regard to forest vitality.

The RVC stated that the Board should act cautiously and rely on Mr. Bouman's evidence which it claims demonstrates that vegetation damage is already being caused by SO_2 emissions. The RVC indicated that if Caroline reserves are to be developed in the overall public interest, it must be done in an environmentally sound manner. In its view, this would make the Husky proposal more favourable.

The RVC suggested that approval of either project should be granted subject to a number of conditions which are listed in Section 3.36. The Board has indicated, in Section 8.2.1, that emissions and related impact monitoring in the area are important and that it will work with Alberta Environment to ensure an appropriate program is designed and implemented. The Board is not willing to condition its decision with the monitoring suggestions of the RVC, but will consider them during the design of the monitoring program.

Regarding the matter of SO_2 emissions, the Board is not prepared to adopt a declining

level condition as suggested by RVC. The Board considers the forest and soil impact possibilities raised by RVC as serious, but cannot see substantive evidence to support the concern. The Board notes that the extensive long-term studies by federal scientists concluded no material detrimental effects beyond the immediate area of the Ram River plant. The Board and Alberta Environment have the jurisdiction to review matters if in future negative effects from regional emissions are shown to be occurring.

Consistent with the discussion of regional plant emissions for each proposal, assuming no independent reductions at the Ram River plant, the Board sees the Husky proposal as having an advantage in reducing total regional SO_2 emissions. However, the Board notes that if the RVC concern about possible forest vegetation damage is correct, approval of the Ram River plant to process the Caroline gas reserves would result in no net SO_2 reductions in the area of this plant. The Board believes this would tend to offset the Husky advantage relative to vegetation and reduced SO_2 emissions and, as a result, sees little difference between the projects in terms of impact on vegetation.

8.8 Soil

The Caroline development proposals may have two forms of impact on local soil conditions. The first is loss of soil materials due to improper handling and storage, which could impact on eventual reclamation success particularly along the required pipeline ROWs. The second is a deterioration of site and surrounding soils due to contamination by spills or sulphur dusting. (Impacts to regional soils due to sulphate deposition are dealt with in Sections 8.2.1 and 8.7.)

8.8.1 Soil Conservation

All of the regulated pipelines associated with each proposal require the submission of a Development and Reclamation (D&R) Plan which addresses, among other things, the soil conditions along the pipeline route and the actions required to mitigate the effects of disturbance on soils. Some potential negative impacts that pipeline construction may have on soils include

- loss of topsoil due to erosion,
- mixing of topsoil and subsoil horizons,
- redistribution of soluble salts and calcareous materials, and
- soil compaction.

The proposed Shell D&R Plan examines the gathering system, the liquid sulphur and water pipelines, and the NGL (Federated) products line. The Husky draft D&R Plan includes the sour gas transmission pipelines, the water pipelines, and the NGL (Federated) products line. The Board is of the view that either proposal would be acceptable in terms of pipeline soil conservation and protection, and no significant difference exists between the proposals.

Unlike regulated pipelines, the remaining proposed facilities do not require a D&R Plan. The extensive hydrogeological studies of Site E by Shell have provided a good data base on existing soil conditions which would be applicable to either proposal. Since the Husky gas transmission plant site would be significantly smaller, proper soil removal and conservation should be somewhat less difficult for Husky than for Shell, which would favour the Husky project. Shell had less data for conditions at its proposed Shantz sulphur handling facilities but did commit to continuing a detailed investigation of both the soil and hydrogeology at that location. Husky did not comment on soil conservation for its expanded Ram River site.

8.8.2 Soil Contamination

At Shell's proposed Site E gas plant, measures to protect the soil (and groundwater) from contamination would include a combination of

synthetic and natural clay liners on all areas used to store contaminated liquids. Shell said the possibility of on-site spills of deleterious chemicals was low and would not likely affect large areas. Liners or paving would also be used around the potential sulphur block pad area at Shantz. Sulphur dusting levels at the Shantz facility were predicted to be very low.

Husky has had a soil monitoring program for several years in the vicinity of its Ram River plant. This study is aimed primarily at delineating the surface area contaminated by sulphur dust. Husky reported that to date, roughly 1700 ha have been affected to various degrees. It has carried out a soil liming program in order to neutralize the potential for localized soil acidification. In addition to sulphur dust, Husky reported an on-site condensate spill. This spill has been dealt with to some extent, but reclamation efforts will likely continue for some time.

During the hearing, Husky committed to employing whatever technology was required as a result of expansion, to maintain sulphur dusting at no more than current levels, but was unable to confirm the technology which would be used. This committment was in part a response to the recommendation from a number of interveners, including the RVC and PALSS, that mitigation of any of the sulphur dust problems should be stipulated in any Husky approval. CAB recommended that Husky's approval be further conditioned to require Rotoform sulphur forming facilities at Ram River. The Board will require that the sulphur dusting problems be rectified, but will not, at this time, stipulate a particular means. (The impacts of sulphur dusting at the Husky plant are also discussed in Sections 8.3, 8.4, and 8.7.)

8.8.3 Conclusions Respecting Soil

The Board is confident that with appropriate measures for soil conservation, pipeline and facility construction by either applicant could take place with minimum impact. Construction practices have improved over those of the past and the Board recognizes the efforts that industry has made to achieve better topsoil salvage and protection. The Shell proposal would require development of a larger plant site at Site E. However, this disadvantage is offset by Husky's need to expand the Ram River site and to develop the relatively large sour gas transmission pipelines. The Board sees each applicant's potential for achieving the necessary soil protection and conservation objectives as being approximately equal.

With regard to soil contamination, the Board notes that while Husky has committed to not exceed current levels of sulphur dust production at Ram River, extensive soil contamination has already occurred and could continue in the future. Since the Shell sulphur forming process would produce less sulphur dust, the Board views this as an advantage for the Shell development.

8.9 Conclusions Respecting Environmental Impacts

As indicated in the introduction to this section, there are several biophysical issues which the Board has considered in assessing the environmental aspects of the proposals before it. On the basis of its considerations, the Board has concluded that either of the projects could proceed without serious long-term or unacceptable effects on the environment. However, in order to accomplish this, care will be required in the design and operation of all facilities. Additionally, on-going effective monitoring will be necessary, and prompt actions will have to be taken when monitoring results indicate problems.

Dr. Kostuch, supported by several other interveners including CAB, suggested that the monitoring of the environment should be

accompanied by an audit of the success of the EIA in predicting impacts. The Board agrees and would require the successful applicant to develop such a program, and would further require public input into its design.

In comparing the environmental aspects of the two proposals, the principal advantage to the Husky proposal is that total regional emissions of SO_2 would be reduced. As a result, the models predict that there would be fewer occasions when ground-level concentration standards are exceeded. This reduced level of SO_2 emissions, in terms of impact on the environment, is offset to some extent by concerns about continuing sulphur dusting and sulphur block fires at the Ram River plant. Also, vegetation in the general area might be less affected by the dispersion of the emissions over a larger area, which would occur if a Shell plant provided a new point source for SO_2 emissions a considerable distance from Ram River.

The CO_2 emissions would be similar for each of the proposals and the NO_x emissions would be slightly lower for Shell.

There is little to choose between the two projects in terms of potential impacts on surface and groundwater, but the existing sulphur dusting and other contaminant source problems at Ram River give a slight advantage to the Shell proposal. The same is true with respect to potential impacts on soils. There is similarly little difference in terms of impacts on wildlife and fish, but Shell may have a modest advantage due primarily to the expectation that unwanted access could be better controlled for its project.

Overall, the Board recognizes the real advantage of the reduced SO_2 emissions related to the Husky proposal. However, it believes the advantages which the Shell project would have with respect to most other environmental aspects offsets a considerable portion of the Husky advantage. The Board therefore concludes that the Husky project has only a modest environmental advantage over the Shell project.

9 RISK TO PUBLIC SAFETY

In this section of the report, the Board first analyses the risks to public safety which might result from the projects. It then deals with the need for emergency response planning.

9.1 Risk Assessment

9.1.1 Introduction

The Board has for many years enforced policies regarding sour gas emergency planning zones and the establishment of appropriate setback distances between the public and sour gas facilities, including wells, pipelines, and processing plants. Setback guidelines have been established using a combination of predictions of atmospheric dispersion behaviour, risk assessments, judgement based on actual sour gas releases from blowouts and pipeline ruptures, and the results of field simulations of sour gas releases.

Drilling for, producing, transporting, and treating sour gas can present a number of difficulties, including fouling and coagulation of drilling fluids, or rapid stress corrosion or hydrogen-induced cracking of metals. If high H_2S sour gas is released into the atmosphere, it may,through inhalation, be toxic to humans and animals proximal to the release. Over the years, improved design of equipment and procedures have been implemented. These improvements in the handling of sour gas have reduced the risks to industry workers and members of the public.

Despite these achievements, public concerns regarding sour gas have continued. The Board has acknowledged these concerns in a number of ways, including recent work on the development of new models (GASCON and GASRISK) to analyse the atmospheric dispersion of gases and the risks resulting from sour gas releases. Their development included an extensive field measurement program. The issue of whether or not the hearing should be delayed pending completion of this work was raised at both the pre-hearing meeting and at the outset of the hearing itself. Although the work was at a pre-release stage, Board staff were able to assist the applicants and interveners in successfully applying the new GASCON and GASRISK models to the respective Caroline proposals.

Sufficient time for review of the model results appeared to be provided over the course of the hearing to satisfy intervener questions and concerns. Both applicants contended that the GASCON and GASRISK results supported the work on project-related risk that they had already submitted.

9.1.2 Risk Terminology

The word "*risk*" can be used to describe hazards, chances, or odds. In the context of this report, risk is the frequency of an event times the consequences of the event. Therefore an event which has a low probability of occurring but severe consequences if it does occur may have an equal risk value to a higher probability event with small consequences.

Individual risk is the probability of death per year for an exposed individual. Societal risk is the number of estimated fatalities in a specified period of time, in an exposed group.

Comparative risks are often done on an annual average individual risk basis, eg.—as an individual has around 200 chances in a million of being killed in a motor vehicle accident each year, but less than 1 chance in a million of being killed by lightning. These comparisons are useful, but it must be recognized that some risks are voluntarily accepted by individuals, while others are not.

Individuals are generally prepared to voluntarily accept risks which are higher than the risks which may be involun-tarily imposed on them.

In their risk analyses, both applicants dealt primarily with possible human mortality due to acute toxicity from a short-term accidental high H_2S sour gas release. The issue of long-term human health effects of sulphur gases (e.g. SO_2) at lower concentrations is addressed in Section 10.2.8 of this report. The focus of the review by the applicants was on the potential risk from a sour gas release; however, both dealt with other risks such as a NGL pipeline release and fires or explosions at processing facilities. The risks to the public related to these facilities are significantly less than risks due to sour gas releases from high H_2S volume pipelines or wells.

9.1.3 Risk Criteria

Neither Alberta nor Canada has regulatory guidelines setting levels of acceptable industrial risk. Canada's Major Industrial Accidents Coordinating Committee (MIACC) is currently formulating risk assessment guidelines for Canadian municipalities, and the Board is involved in this committee.

There was considerable discussion at the hearing on standards of other countries regarding levels of acceptable risk. The United Kingdom was referenced by Husky as having established an upper and lower level on individual and societal risks, but Husky took no position on this evidence. Shell said that it did not attempt to establish an *acceptable* individual risk number, and added that population density is a factor that must be considered.

The Board accepts the position of both applicants on the issue of not establishing risk criteria or acceptable risk levels as a result of the Caroline applications. Through further work by groups like MIACC, such criteria may eventually be established, as has been done by the Health and Safety Executive for the United Kingdom. However, in the interim the Board believes that judgements regarding the acceptability of various levels of risk should continue to be based on the best scientific appraisal of the level of risk, the nature of the proposed project and the benefits which would flow from it, the location of the project relative to population centres, and the mitigative measures proposed by applicants.

9.1.4 Risk Assessment for the Caroline Proposals

Shell provided risk estimates for the completed wells, the proposed field gathering system, the Site E gas plant, and the possible future Bearberry facility. Shell stated that there would be additional wells drilled in both the Caroline and Bearberry fields, but no estimate of risk over the life of its project was given. Shell did provide an estimate of how risk would change from year one to year seven of the project. Shell did not consider risk from capped or abandoned wells.

Husky provided risk estimates for its proposed gas transmission plant at Site E, the sour gas transmission pipelines, and the incremental risks at an expanded Ram River plant. The estimates were for the first year of operation, which it assumed to be a maximum. Husky did not provide information on the field gathering system or wells.

Neither applicant provided risk estimates for existing facilities in the area, the incremental traffic, or for changes in population which would result from the Caroline project. Shell did, however, look at overlapping risks from facilities that it proposed.

When the new models became available, both applicants made calculations using GASCON and GASRISK for their respective Caroline proposals. When compared to their previous work, the GASCON and GASRISK models generally showed risk to be less. The Board generally concurs, but notes that there were a few situations where the new models showed a higher concentration of H_2S and subsequently a higher probability of lethality. However, final risk assessments are a summation of many possible cases over the range of events. For this reason, the Board believes that those few situations would not significantly affect the basic risk assessment and believes that the focus of attention should be on the risk studies included in the applicants' original submissions.

The Board notes that the GASCON and GASRISK model work pointed out that matters such as horizontal versus vertical plume jets and indoor/outdoor air exchange rates have a significant influence in assessing levels of risk. Similarly, the type of dispersion co-efficients used and the well blowout and pipeline rupture statistics are important.

Shell suggested that the risks from its project would range from approximately 2 to 8 in a million for individual annual risk at existing setback distances. For societal risk, Shell said that 13 would be the maximum number of fatalities, with a probability of occurring once in a million years. The risk estimates supplied by Husky were of the same order of magnitude, but as indicated previously, its estimates excluded the wells and field gathering system. These facilities represent, by far, the greatest portion of the total risk associated with either proposal.

Shell claimed that Husky's sour gas transmission pipelines would present an incremental risk, and using Husky's own numbers, it estimated that the risk would be approximately double that of Shell's proposal. Shell said that although Husky could safely transport the gas for the Caroline project, to take on additional risk when lower risk alternatives are available would not be prudent. Husky countered that while its calculations were highly conservative, if Shell had used the same calculation procedure, Husky's proposed transmission pipelines would produce some incremental risk, but much lower than Shell's estimate.

The Board has made a detailed evaluation of the risk assessment evidence put forward by each of the applicants. With respect to Shell's submission, the Board believes that the well blowout statistics used by Shell might have under-estimated the chances of a blowout. However, because Shell used a very high flow rate, based on the maximum absolute open flow (AOF), the overall increase in risk associated with the wells would not be great. The Board also believes Shell may have over-estimated the beneficial effects that would result from its special pipeline design measures, and therefore slightly under-estimated the chances of a gathering system release. Combined, these adjustments might increase the range of individual risk associated with the Shell project by about 10 per cent.

Regarding the Husky proposal, the Board agrees that Husky's calculations of risk were more conservative than were Shell's. Adjustments for several factors, such as the particular dispersion co-efficients used and the indoor/outdoor air exchange rates, would lower the calculated risk. If adjustments are made to recognize the possibility of a horizontal release, the calculated risks would increase. However, the most significant difference between the Husky and Shell assessments relates to the chances of a pipeline rupture. Shell indicated that its special measures, some of which are described in

Section 2.2.1, would greatly reduce the chances of a release, and the Board generally agrees. Husky stated that if its project were approved, it would institute similar measures for its proposed sour gas transmission pipelines. On the basis of this undertaking, the Board would reduce the risk associated with Husky's sour gas transmission pipelines by a factor of three or four. The Board believes that with such an adjustment, Husky's proposed sour gas transmission pipelines would represent an increased risk to the public when compared to the Shell project, but not a doubling as suggested by Shell. The incremental risk of the Husky project would likely be in the range of 10 to 20 per cent when compared to the Shell project, because the Husky transmission pipelines would be situated in a sparsely populated area and also because pipelines in general have lesser risks than wells.

At least one intervener suggested that the Husky transmission pipelines should have more block valves to reduce potential release rates. The Board does not believe this is warranted having regard for the fact that Husky already considered its risk estimates in order to optimize valve locations. The optimization process includes the fact that at some point, it would not be prudent to have additional valves as these are placed on the surface where they are subject to exposure and third-party damage. Other interveners expressed concerns that the incremental risks associated with the Caroline project should be added to those which now exist. The Board notes that while the level cannot be determined accurately, there is some existing risk. Based on its understanding of the number and types of existing wells and pipelines, the Board believes the current maximum individual risk is less than 1 in a million; therefore, the current level of risk would not significantly alter the conclusions reached above.

9.1.5 Mitigative Measures

The Board notes that both applicants have identified and committed to measures to reduce risk that go well beyond the current Board and industry standards. Shell's special measures include increased pipeline wall thickness for buried sour pipelines resulting in a 30 per cent lower stress level, and deeper burial depth. The Board also understands that individual sour pipelines would be designed to accommodate internal pipeline inspection tools and that a baseline inspection would be performed. Detailed stress analysis would be conducted for the entire length of all sour gas pipelines using site-specific soils data. Shell's use of a sophisticated mass-balance leak detection system would enhance the operating reliability of its pipelines and likely reduce risks. The installation of three ESD valves at each well site would also reduce the risk of any well continuing to produce in the event of a pipeline failure.

The Board agrees that Husky's proposed dual transmission pipelines would reduce the release volume resulting from a pipeline failure. Husky's implementation of baseline surveys immediately following construction and subsequently at regular intervals during operations would also be helpful in preventing a release. Additionally, Husky's pipeline stress level would be at 47 per cent, which would assist in alleviating concerns of a pipeline failure. Should a pipeline failure occur, Husky's proposed compensated mass balance system would assist in a quick detection of a leak. Husky also indicated, in response to certain interveners, that it would investigate placing berms at valve sites to deflect horizontal jets into the atmosphere.

The Board believes that the mitigative measures proposed by each of the applicants

would be adequate to minimize risks. However, if Husky's project were approved, it would be required to adopt sour pipeline design measures for all of its pipelines similar to those proposed by Shell.

9.1.6 Setback Distances

Setback distances are the minimum distances between sour gas facilities, including wells, and residences and other public facilities. The minimum distances are set out in Interim Directives *ID 81-3* and *ID 87-2* and the associated amendments. BLCOA proposed that a new setback distance from any large group of people should be at least 3.5 km for either Shell's or Husky's proposal. A technique for calculating the 3.5 km was also provided. The Board notes that most of the large groups in the area are situated at distances greater than 3.5 km. The Brunners also requested increased setback distances.

While the Board recognizes that an increased setback distance might provide some additional safety margin, given the estimated level of risk for the proposed facilities, the Board is not prepared to increase the required separation distance. In taking this position, the Board is also recognizing the tendency for risks to decrease as reserves deplete. In this regard, some interveners have suggested that the risk will increase with the age of facilities. Historical data shows that this has generally not proven to be the case.

9.1.7 Conclusions Respecting Risk Assessment

The Board believes that the risks to public safety would be acceptable under either proposal, provided that all proposed mitigative measures were fully implemented, great care and caution were exercised in all operations, and proper emergency response plans were in place. In terms of a comparison, the Shell proposal has an advantage because the addition of the Husky sour gas transmission pipelines represents a small but real additional incremental risk.

9.2 Emergency Response Planning

9.2.1 Introduction

The Board will require that a comprehensive emergency response plan is in place prior to start-up of the Caroline project to ensure public safety in the event of an accidental H_2S release. Shell and Husky have both prepared preliminary emergency response plans designed to address the needs of their respective proposed facilities. These plans must ultimately incorporate detailed resident information and would be reviewed and approved by the Board prior to implementation. This would occur before plant start-up.

9.2.2 Response Plan Co-ordination

Shell developed its Emergency Procedures Manual assuming a single operator managing a completely integrated gas plant and gathering system. Thus, the Shell proposal would have one control centre for plant and field operations.

Husky's Emergency Procedures Manual is intended to be incorporated into the existing Ram River Emergency Procedures Manual. Husky stated it would monitor the Caroline field and gathering system, Site E gas transmission plant, sour gas transmission pipelines, and the expanded Ram River plant, from both the Ram River plant and the proposed Husky gas transmission plant. According to Husky, an emergency response for the plants and the transmission pipelines would be Husky's responsibility while an emergency response for the wells and gathering facilities would be Shell's

responsibility, and both companies would jointly handle the common point or points of overlap. Husky indicated that its personnel would be available in a back-up mode for the gathering system and field facilities should conditions warrant.

The Husky proposal would involve the co-ordination of the Husky Ram River Emergency Response Plan for the transmission pipeline system and the Shell Caroline Emergency Response Plan for the wells and gathering system. Husky's proposal would also potentially involve as many as four control centres, two at the expanded Ram River plant, one at the Husky Caroline gas transmission plant, and another control centre for the Shell gathering system.

The Board accepts that Shell's proposal, in which the plant would be close to the field and which would use a single emergency response plan for the entire area, has the advantage of simplified communications and would likely result in more effective emergency response capability. However, although the Board has always encouraged "*one operator*" emergency response plans for sour gas plants and gathering systems, the Board notes that currently there are several plans, approved by the Board, which have separate operators for the gathering systems and sour gas production facilities.

While the Board believes a suitable plan could be developed for Husky's project, the relative lack of complexity gives the Shell proposal an advantage. A very detailed communications plan linking a number of centres together would be required should Husky be the successful applicant. If that were the case, the Board would expect Husky to prepare a response plan that clearly defines the separate and joint responsibilities and the appropriate emergency response procedures.

9.2.3 Single Road Access

During the hearing, several interveners raised concerns regarding evacuation problems where single road access exists. BLCOA pointed out the single road access route from the Burnstick Lake Development. CRAG, representing families located near the proposed north compressor site, discussed the problem of single road access in the direction of the north compressor station. In particular, CRAG noted the limited access possibilities for several of its members who are located at the end of a dead-end road.

The Board concurs that any emergency response plan for the Caroline field must address this problem and provide an appropriate evacuation scheme for areas with single road access. One possible solution may be the construction of some additional or alternative access roads for the affected individuals. The Board would require the successful applicant to explore all possible solutions with affected parties to resolve these evacuation problems.

9.2.4 Warning Systems

Concerns regarding effective warning systems were also raised at the hearing. BLCOA recommended the installation of two permanent first alert warning systems at the Burnstick Lake Cottage Development and at the public campground, to give audible warning of a potential hazard. The Brunners expressed a lack of confidence in the effectiveness of either the phone system of notification or the personal operator visit notification method and also proposed a remote control warning system.

In the past, the Board has not encouraged the use of audible warning systems, such as sirens, for emergency purposes. Sirens must be tested on a regular basis and in winter

weather conditions they may not always be dependable. These devices are targets for vandals, and constant education of the public is required to ensure that warnings are understood. Notwithstanding these potential problems, sirens can be and are utilized as warnings. The Board agrees with BLCOA that some form of early warning is appropriate for the Burnstick Lake Cottage Development and campground because of the general absence of telephones. It would therefore require the successful applicant to install sirens or some mutually acceptable alternative at these locations.

While the Board acknowledges the health and safety issues raised by the Brunners, the Board cannot agree with Mrs. Brunner that the phone system and personal visits by operators are not effective for communication in emergency situations. It is the Board's experience that the combination of these notification methods during emergencies has proven to be reliable. The Board would require, however, that the successful applicant specifically identify Mrs. Brunner's desire for early notification in its emergency response plan.

The Board would also require that comprehensive air monitoring instrumentation be located in the vicinity of the Brunner property, to record the type and source of possible fugitive emissions. Placement and duration of air quality monitoring equipment should be mutually agreed upon by the operator and the Brunners. If necessary, the Board would assist in such discussions regarding the location and type of monitoring equipment and would expect to involve Alberta Environment. The Board believes that this air monitoring equipment should be installed and operational by the successful applicant for at least 1 year before start-up of the Caroline facilities.

The Board believes that Mrs. Brunner's request to have safety equipment for herself and family on the property should be deferred at this time. The Board believes that the data from the previously referred to air monitoring equipment should be jointly reviewed with the Brunners after the facilities have been in operation for at least 6 months. If that review suggests there is a problem, appropriate action would then be taken.

9.2.5 Emergency Planning Zones

Each applicant proposed a 4-km radius for its emergency planning zone. Within the zone, the public would be knowledgable of the plan, and actions to be taken in the event of an emergency would be detailed. The Board has considered BLCOA's proposal with regard to the Husky application that a second planning zone be established extending up to 16 km. The Board believes that extending the zone to 16 km would make it very difficult to manage and is unwarranted given the risk. The Board also notes that Shell is proposing a further 4-km awareness zone around the 4-km planning zone for its Caroline project. Residents within this zone would be made aware of the emergency response plan and how it operates. The Board would require Husky to have a similar 4-km awareness zone but would not adopt the 16-km recommendation. Notwithstanding the awareness zone, the Board would require that the proposed 4-km planning zone be extended to include nearby centres of population, specif-ically the town of Sundre, Burnstick Lake community, and the area around Westward Ho.

9.2.6 Community Input

The Board notes that either proposal would involve a construction period of at least 2 years. An emergency response plan would not

be required until several months before start-up of the facilities. The Board therefore believes that either applicant would have sufficient time to develop an emergency response plan that would reflect input from the residents in the Caroline project area.

In order to accomplish this task, the Board believes that the successful applicant should establish an Emergency Response Awareness Committee in conjunction with a community-based committee as suggested by CAB and discussed in Section 3. This committee should be made up of a broad cross-section of community leaders, concerned citizens, local government officials, and other industry representatives. The committee would provide the successful applicant with community input and concerns respecting the emergency response plan.

The Board believes that with input from the proposed Emergency Response Awareness Committee, either Husky or Shell could prepare an emergency response plan that adequately addresses the concerns of the interveners, and also be acceptable to the Board.

9.2.7 Conclusions Respecting Emergency Response Planning

The Board finds that the emergency response proposals submitted by Shell and Husky meet the Board's requirements for such plans. The Board does, however, have some concern with regard to the co-ordination of separate emergency plans and the communications between the different control centres, should Husky be the successful applicant. It thus sees an advantage for the Shell proposal.

The Board would like to comment on an item which was not raised at the hearing, but is an important part of an emergency response plan. The Board's ignition policy for sour wells is designed to ensure that if there is an uncontrolled or partially controlled H_2S release which could endanger health and safety, the public is to be protected by either evacuation from the area or, if evacuation is not practical, by ignition of the well. To accomplish this, the Board requires immediate ignition of an uncontrolled release from wells that have a very high potential H_2S release rate and are located near population centres where evacuation would not be feasible. The only exception where ignition could be delayed would occur if the Board is satisfied that control could be quickly regained and that the health and safety of adjacent residents would not be at risk. The Board believes that this policy applies to the Caroline project wells and would expect the successful applicant to reflect the policy in its emergency response plan.

10 SOCIO-ECONOMIC IMPACTS

10.1 Introduction

Both applicants submitted an SEIA that examined the effects of their respective proposals on the project area. It should be noted that each applicant's definition of the project area for socio-economic purposes was different. Shell considered its proposal to affect an area that included the communities of Caroline, Sundre, Rocky Mountain House, Olds, Innisfail and Didsbury, as well as portions of the MD of Clearwater No. 99 and the County of Mountain View No. 17. Husky's project area was somewhat smaller as it excluded the communities of Olds, Innisfail, and Didsbury. The differing definitions of project area were, in part, because of the different locations of the proposed facilities.

The Board has attempted to identify both the possible negative social impacts and the social benefits associated with each project. Impacts were examined to ensure that any negative impacts are reasonably acceptable and are offset by benefits to an appropriate degree. They were also compared to determine whether either project holds an advantage in terms of this particular aspect of the public interest.

It should be noted that while certain other matters, such as environmental impacts or risks to safety, also have the potential for social impacts on a community, they are dealt with elsewhere in this report.

10.2 Social Impacts

10.2.1 Traffic

Shell estimated that incremental traffic on area roads during peak construction of its project would range from 930 to 4575 vehicles per day. The most significant increases in traffic would occur on the road south of Caroline and north of SR 587. To reduce the negative impacts associated with increased traffic on local roads, Shell planned to upgrade major traffic routes in the vicinity of its proposed plant at Site E. These improvements would include reducing corners, widening and grading roads, and eliminating dust by hard surfacing the Caroline road. Shell also planned to bus transport non-local construction workers to the job sites during the proposed 4-day work week in order to help to reduce traffic, particularly on weekends.

Husky estimated that incremental traffic on area roads during peak construction would range from 1031 to 3218 vehicles per day. With a wider distribution of its construction camps as compared to the Shell project, increased traffic from the Husky project would be spread over a broader area. The secondary road south of Caroline, in particular, would see much less incremental traffic under Husky's proposal. The same upgrades to secondary roads around Site E and the field and gathering area would occur whether the Husky or Shell project proceeded.

The Board believes both applicants have undertaken adequate steps to control the impact of incremental traffic during construction, although on-going co-operation with local governments will be needed. Husky's proposal offers a slight advantage, as the increased traffic would be spread more evenly throughout the region, and not concentrated near urban areas. Whichever project proceeds, the Board agrees with the Mountain View Group that the proponent should attempt to schedule work shifts such

that the peak traffic would not coincide with school bus times. If the Shell project proceeds, the Board agrees with the suggestion from the same group that efforts be made to minimize the chances of an accident involving a school bus and a sulphur unit train. The Board would expect Shell to work with CP and others towards that objective.

During the operations phase, both applicants considered incremental traffic to be relatively minor and to pose no significant social impact on the region. The Board concurs with this assessment.

10.2.2 Noise

Large industrial projects in rural and recreational areas have the potential to raise both short- and long-term concerns regarding increased background noise. Short-term impacts usually arise during the construction period from sharp, loud, intermittent noise sources. Long-term impacts generally occur during the operating phase and may result from a general increase in ambient sound levels from vehicles, compressors, and other similar sources. During construction, the develop-ment activity schedules at Site E for either Shell or Husky would be similar, and both applicants' proposals to upgrade area roads and install self-contained construction camps would help minimize traffic-related noise during construction. In addition, all heavy trucks would use Highway 22 and SR 587, thus avoiding the Caroline townsite.

The major difference between the two proposals, in terms of noise during construction, appears to result from the smaller plant required by Husky at Site E. Husky would have an advantage because the attendant camp and activity levels would be less than required for the Shell proposal. Husky's expansion of the Ram River plant, because of its remote location, would also not result in significant noise impacts. The Board notes that while Husky tentatively proposed a construction camp for the transmission pipelines in the Ricinus area, no evidence was presented regarding methods to control noise impacts or the risk of such impacts occurring at this site.

Shell committed to meet or surpass the Board's current noise guidelines[6] and it included a number of noise control features in the design of its proposed facilities, including electric drive compressors equipped with variable speed fans. Shell retained acoustical consultants to conduct a noise impact assessment to ensure that the design of Shell's proposed facilities would keep noise level increases to an acceptable minimum. The locations that were chosen for the assessment included twenty-six permanently occupied or seasonal residences on lands in the vicinity of Shell's three proposed compressor sites and the proposed gas plant location. The assessment indicated that all of the predicted sound levels from the proposed Shell facilities would be below the required nighttime and daytime values at all the residence locations. Shell stated it would also complete a post-construction noise survey to ensure the noise control requirements were being met.

PALSS expressed concern about potential noise problems at the Shantz sulphur loading facilities due to the railroad. Shell did not supply any specific information on what measures, if any, may be taken to mitigate against excessive noise levels at Shantz. Notwithstanding, the Board notes that *ID 88-1* would apply to the Shantz facilities and Shell's commitment to conform to the guidelines should keep noise to acceptable levels.

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(6) Interim Directive *ID 88-1*, Noise Control Directive, October 1988.

Experts for CRAG projected a larger traffic noise impact for the Shell project than predicted by Shell. This was due to CRAG's view that there would be a need for more goods and services for Shell's proposed camp and for a greater number of social and recreational trips by the workers than Shell had anticipated. The Board cannot accurately predict what the actual associated traffic will be but expects traffic impacts would be somewhat greater for Shell's proposal, most of which is in a populated area, as compared to Husky's. Regardless of which project proceeds, the Board would expect either applicant to monitor the situation closely for possible traffic noise impacts, and take the action necessary to adhere to the noise control requirements.

The Board notes that both Shell and Husky have committed to meet or surpass the requirements of *ID 88-1*. The Board believes this is an achievable target given the remoteness of the Ram River plant for Husky and the three-phase noise assessment program committed to by Shell. Overall, with respect to noise, the centring of the Husky proposal at the somewhat remote existing Ram River plant location gives Husky's project an advantage over Shell's.

10.2.3 Visual Impacts

The degree to which the visibility of a facility affects a population depends on the physical size of the facility, the number of people in the vicinity, the degree to which the facility corresponds to existing land use, and the general population's perception of the facility.

For both the Shell and Husky projects, the visual impacts of the wells and gathering system would be equal since they would be designed, built, and operated in a similar manner for either proposal. Although visual impacts would likely be significant during construction of the gathering system pipelines, almost half of the proposed ROW is on cleared agricultural land and would be reclaimed after construction. Each of the three compressor stations would have a 75-m emergency flare stack, but there would be some natural tree-screening. At the compressor stations, lights would be shaded, facilities would be painted earth tones where practical, and the sweet gas pilot flame burning at the flare stack would be partially shielded by a windshroud, thereby making the flame less visible.

Visual impact of Shell's proposed liquid sulphur pipeline should be slight after completion of construction and ROW reclamation as approximately 60 per cent would traverse presently cleared agricultural land. The proposed Shantz sulphur forming and handling facilities would be located in a mainly cleared agricultural area adjacent to the Mobil Harmattan gas plant, and the presence of the existing plant should lower incremental visual impacts. However, this facility would likely be visible from some local roads and possibly from the homes of some nearby residents.

The most visible Shell facility would be the proposed sour gas processing plant at Site E. Although there would be no sulphur block at the site, the proposed gas plant would include one 85-m incinerator stack and one 85-m emergency flare stack. Shell indicated it would inject steam into its proposed plant flare to help reduce smoke and flame visibility. Shell's proposal would require development of 60 ha of land, a portion of which is presently cleared. Trees to the east of the plant would be maintained as a partial sight barrier. A 1000 to 1200 person construction camp at the proposed gas plant location would be required as well as a 400 to 500 person camp at an as yet undetermined location, but likely near James River Bridge.

Husky's proposed Caroline gas transmission plant at Site E would be situated in a currently cleared area of approximately 10 ha, and would likely also be partially screened by stands of trees. Husky's gas transmission plant would utilize one 78-m-high emergency flare stack and the maximum height of its other plant processing vessels was estimated to be about 24 m. Two of the proposed Husky construction camps would be located in more remote areas, while a 300 person camp would be located near James River Bridge as part of the camp required for construction of the gathering system. A smaller 100 person camp would be located at Site E.

The greater part of the ROW for the Husky transmission pipelines would be through forested land, and reclamation procedures would lessen the visual impact. Nonetheless, the linear development in a forested area would be visible. The new processing facilities, proposed for the expansion of the Ram River gas plant, would have a low incremental visual impact because of the presence of the existing plant and the absence of a permanent population in the area.

The Board believes that all the proposed facilities represent some industrial intrusion into a rural setting. Recognizing the efforts by the applicants to minimize the impacts, the Board considers the visual impacts of both projects to be acceptable. It notes that both Shell and Husky have taken visual impact into account during selection and design of their respective facility sites.

The Board believes that the visual impacts of the various permanent components of either project are essentially equal, with the exception of the proposed facilities at Site E and the clearing for Husky's transmission pipelines. Although Husky's proposed Caroline gas transmission plant would be visible to nearby residents, it would be smaller in areal extent and height than Shell's proposed facility, and would include one 78-m stack as opposed to the two 85-m structures proposed for the Shell plant. In terms of visual impacts, the Board considers the overall size of the Site E facility favours the Husky configuration, although this is somewhat offset by the additional forest clearing associated with the Husky transmission pipelines. As Husky would have fewer construction workers located in populated areas than would Shell, the visual impacts of the Husky construction camps would also be somewhat less. In general, the visual impact of the Husky proposal would be less than for the Shell proposal.

10.2.4 Odours and Fugitive Emissions

The Board recognizes that operators of sour gas facilities cannot completely control odours and fugitive emissions, and this causes concern for residents in the area. The stated objective of both applicants was to ensure that there would be no significant nuisance odours from the field, the Site E facilities, or the Ram River plant, and that the latest technology for odour abatement would be incorporated into all the facilities.

Shell stated that it would utilize back-up safety features on all valve, pump, and compressor seals and that vapours from vessels would be collected and sent to the flare system. Shell said it would perform periodic audits, routine monitoring with permanent and portable H_2S detectors and routine plant maintenance as part of its on-going leak detection system. Shell indicated that odours could virtually be eliminated by appropriate equipment design selection and audits.

Husky stated it had not finalized the details regarding the design of its vapour recovery system. However, it stated it would ensure that all process vessel relief and vent valves would be connected to the flare system and

that its vapour recovery system would be incorporated to remove odours from both the condensate storage tanks at Site E and the sour water stripper. Sour water would be collected in a pressurized vessel at its proposed gas transmission plant and the sour water vapours would not be vented to the atmosphere.

Husky's project would have fewer process vessels at Site E than Shell, which would reduce the likelihood of fugitive emissions. The Shell proposal, on the other hand, would offer less chance for sulphur handling emissions at the Shantz site than would be the case for Husky at its Ram River complex. However, as Shell's Shantz facilities would be in a more populated area, appropriate odour abatement measures would be crucial.

With respect to odours and fugitive emissions, either proposal would be satisfactory to the Board subject to certain conditions, and neither applicant appears to have a significant advantage. If Shell's proposal were approved, the Board would expect to review the results of the monitoring program, particularly the effectiveness of the proposed leak detection system. If Husky's proposal were approved, the Board would require that each condensate storage tank at Site E have an appropriate floating roof similar to the design proposed by Shell. The Board would also require Husky to increase its proposed inspection frequency of both Site E and transmission pipeline facilities.

10.2.5 Community Infrastructure

A large development project, particularly when located within a rural, sparsely populated area, can result in strains upon the existing services infrastructure within the community. Both projects would impose some costs on the local community infrastructure, mainly because of costs associated with road construction and expansion of some social services. Both the Shell and Husky projects would require approximately $5 million of improvements to roads around Site E and the proposed field and gathering facilities. Some of the road improvements, such as the Caroline road from the village south to SR 587, would be cost-shared between Shell and the M.D. of Clearwater. Other roads, such as the 4.8 km of SR 587 west of Highway 22, would be paid for by Alberta Transportation. In addition, the Husky project proposes a $4.3-million upgrade to the Swan Lake road to be paid by the working interest owners.

Evidence provided in the Shell and Husky applications, and supported in submissions from local governments, indicate that sufficient schools and hospitals exist in the project area to serve the expected population influx. Some additional staff may be required, however, for social and mental health services, particularly during construction. The Board agrees with the suggestion of CAB that the successful applicant should be required to work with the local communities to ensure that the appropriate health and social service infrastructure is in place for the construction phase.

A number of interveners raised the issue of safety and security, particularly in the Caroline and Burnstick Lake areas. Shell stated it would work with the RCMP to ensure that security matters are addressed. Shell indicated that some mitigative measures such as increased working hours and a 4-day work week should significantly reduce these potential problems.

The Board is not prepared to condition an approval requiring the detailed security measures program requested by BLCOA for the Burnstick Lake area. The Board would, however, expect the successful applicant to work with the community, the RCMP, and others as appropriate, to minimize the impact that the presence of a large workforce might

have on security, not only at Burnstick Lake but elsewhere in the region.

The Board concludes that the existing community infrastructure in the area would be adequate, should either project proceed. The modest difference in infrastructure costs incurred by the two projects is not considered to be significant in evaluating their relative merits.

10.2.6 Land Use

In addressing the question of land use, the Board has had regard for the amount of land required for each development, the current land use, and the ease and speed with which the land could be restored.

The total land area required by the Shell proposal (886 ha) and the Husky proposal (803 ha) is generally comparable, despite the use by Husky of its existing Ram River site for the majority of its proposed gas processing facilities. A lesser portion of the proposed development would occur on public lands (*the Green Area*) in Shell's case than in Husky's.

Both proposals would involve the same wells and gathering system, which are located primarily on private lands within the White Area where current land use includes both scattered woodlands and agricultural lands. It is expected that along the pipeline ROWs in the White Area, agricultural use could be restored rapidly, while well sites, compressor stations, and access roads would remain in place over the life of the field, which is estimated to be more than 20 years, before being reclaimed. In the Board's view, the proposed gathering system is consistent with local and regional land use criteria and is therefore acceptable.

The Shell project would require development of approximately 60 ha for its proposed plant site, some 27 ha for the sulphur forming and handling facilities at Shantz, plus temporary disturbance of about 141 ha of land for the liquid sulphur pipeline. Roughly equal disturbance of agricultural lands and of woodlands would be required to develop these facilities. Restoration of the liquid sulphur pipeline ROW to current agricultural use would likely be within 2 to 3 years, while land use changes at the remaining facilities would continue over the project life.

In the Husky proposal, changes in current land use would be required for Husky's smaller gas transmission plant at Site E (10 ha), for the sour gas transmission pipelines (133 ha), and for the associated access roads (65 ha). All these developments would be on public lands, zoned for multiple use within the Green Area. In Husky's case, the greater part of the land disturbed currently contains merchantable timber. This land use would be lost over the life of the project, although the pipeline ROW would be revegetated.

In general, the Board finds the land use changes proposed by both companies to be acceptable, and notes the commitments made by both firms to use existing development corridors where possible. The Board believes that Husky's proposal has a slight advantage in total land use requirements, despite some concern that the 10-ha parcel proposed by Husky at Site E for its gas transmission plant may not be sufficient. This advantage is offset by Shell's ability to more rapidly return at least some of the disturbed land to its current land use. In total, the Board sees little difference between the proposals in terms of land use.

10.2.7 Property Values

The degree to which land values in the Sundre-Caroline region would be altered by the Shell project was raised by several hearing

participants. Those interveners claimed that property values would become depressed for parcels of land situated close to Shell's proposed gas plant and to a certain extent, the gathering system facilities. In particular, they claimed that land purchased for its aesthetic characteristics, recreational use, or solitude would be devalued by the presence of sour gas facilities to a greater degree than would agricultural land.

In anticipation of such concerns, Shell commissioned two studies which reviewed sales of property in the vicinity of a range of sour gas facilities elsewhere in the province. Both studies indicated there was no measurable impact on the value of property which could be attributed to sour gas developments, and that the price of land fluctuated within the normal range of land prices. Shell also said there may even be a positive effect or increase in land value in certain cases where members of the project's permanent workforce prefer to purchase property close to their jobs.

Expert testimony provided by CRAG disputed the reports submitted by Shell. The CRAG evidence stated that major developments can have a negative effect on land prices, and that the conclusions reached by the Shell studies were not meaningful.

Husky stated that its proposal would have essentially no possibility of affecting private property value now or in the future because of the sparsely populated sites that would be used for the transmission pipelines and plant expansion and the fact that the transmission pipelines, the proposed Husky gas transmission plant, and the existing Ram River plant would all be on Crown land.

Several interveners preferred the Husky proposal since Husky's gas transmission plant at Site E would be smaller in size than the proposed Shell plant, and thus they believed it would have less tendency to discourage future potential buyers for nearby private land.

The Board believes that a large sour gas plant and its associated physical infrastructure would, despite Shell's evidence, likely have some negative effect on property values for those parcels closest to the site which might be used for residential or recreational purposes. This effect would then tend to decrease to at least a neutral or perhaps even positive effect once a certain distance from the plant was attained, because of the impact of a large project on the economy and population of a region. This distance would likely be tied to the visibility of the plant facilities as well as the perception some people may have of sour gas plant impacts. It is reasonable to expect that there would be a lesser impact on agricultural land values than on recreational/residential properties. The Board therefore sees a modest advantage for the Husky proposal with regard to non-agricultural land values in that the proposed Husky gas transmission plant would be considerably smaller than Shell's, and also because the remainder of its facilities would be in a remote location removed from land transactions.

10.2.8 Health

Concerns about the effects that gas plant emissions may have on human health were raised by CAB, Mrs. Brunner, and a number of other participants in the hearing. The matter was also discussed with the proponents at several public meetings prior to the hearing. These discussions occurred because of a general perception in the region that a health study should be incorporated into the Caroline gas development. To address these concerns, Shell funded a study by Dr. H. Bryant of the University of Calgary to describe the methods that could be used to monitor the health of the community as the development proceeds. The study did not intend to address the question of

whether health effects would or would not occur, but the feasibility of detecting community health changes. Dr. Bryant suggested two possible studies, long-term or short-term health effects.

The study report, which was submitted with Shell's applications to the Board, was reviewed by CAB, and that group supported the short-term form of the proposal. This plan would entail the monitoring of emergency room visits at local hospitals, office visits to physicians, school absenteeism, and symptoms experienced by sensitive individuals or groups. It would start 3 months prior to gas plant start-up and continue for 1 year. The long-term health study was not supported by CAB, apparently because of the small regional population size and long latent period for some diseases, as well as the fact that regional plant emissions have declined in recent years. At the hearing PALSS requested a long-term health study. Shell committed to conduct the short-term health study if its project proceeded.

Husky did not fund or investigate any feasibility studies into public health effects, taking the position that no nearby residents exist in the Ram River region and also that the emissions from its Site E facilities would be minimal.

The Board would require that the project which proceeds be designed and operated in a manner which satisfies all existing standards, including those intended to protect human health. It would therefore not expect significant effects on health, for either project, and would not condition its approval to require a health study. If a study is carried out, the Board would urge that its design and conduct have considerable input from the broad public in the area and that the provincial government departments responsible for environment and health be fully involved.

Mrs. Brunner asked that the gas industry assist in developing an antidote for the effects of sour gas. The Board is not in a position to require this of the industry, but is making the request known.

10.2.9 Lifestyle

Perhaps the most significant of social impacts is any negative impact on the lifestyle of people in the area. These impacts can result from many factors, including some dealt with earlier in this section of the report and some dealt with elsewhere. In terms of the Caroline development, the impact on lifestyle is likely to be greatest during the construction period, regardless of which project goes ahead.

During peak construction for either project, more than 1000 workers would be required, many of whom would be hired from outside the project area. This influx of construction workers could have a significant adverse effect on the lifestyle of local residents.

The Shell project proposes two construction camps, the largest being at Site E and a smaller camp somewhere east of James River Bridge. To mitigate negative impacts on the local communities, Shell proposes that both camps be completely self-supporting, including the installation of recreational facilities. In addition, Shell intends to incorporate a 4-day work week with 10-hour shifts. This is intended to minimize construction workers' free time, encourage them to go home for weekends, and reduce traffic by providing bus transportation and shifting the travel to off-peak hours.

The Husky project proposes a minimum of three construction camps with the possibility of four. Husky said that setting up the largest camp at its isolated Ram River plant site and distributing other camps throughout the region would minimize disruption for local communi-

ties. Husky also proposes to incorporate 4-day work weeks and 10-hour shifts and to provide recreation facilities at its camps.

The Board considers both applicants to have undertaken reasonable steps to alleviate the impact of their construction camps on the lifestyle of the local communities. Although the impacts could be significant, the Board believes that either applicant, by working closely with the appropriate local representatives and adhering to all of the commitments made at the hearing, could complete construction of these projects in an acceptable manner.

In terms of comparative impacts, the Husky proposal would likely have the lesser impact as its major camp would be at the relatively isolated Ram River plant site while Shell's main camp would be much closer to urban areas.

During the operations phase of the projects, neither applicant considered its respective proposal to have significant negative impact on local lifestyles and the Board generally agrees. It does, however, expect that there could be some on-going impacts due to the increased population in the region which will result from the development. For example, there could be some inflationary pressures associated with the population influx of the newly hired plant workforce into the area. These should not be great, and neither proposal would have a significant advantage over the other in this regard.

10.3 Social Benefits

Most of the social benefits associated with development of the Caroline gas reserves would be economic gains due to increased expenditures for goods and services and to an expanded tax base. In evaluating the two proposals, the Board first examined the economic benefits which would affect the region where the gas reserves are located. It then reviewed additional economic benefits to the province and the country. With regard to regional benefits, the Board considered a relatively broad area which includes Rocky Mountain House to the north, extends east to Highway 2, and includes significant parts of the MD of Clearwater 99 and the County of Mountain View 17.

10.3.1 Regional Employment

The project area can be expected to benefit from an increase in employment during the construction and operation phases of either the Shell or the Husky proposal. Shell estimated that its project would require a total of 2265 man-years, of which 18 per cent, or 488 man-years, would be supplied locally. It also estimated that when construction activity peaks, 130 indirect jobs and 310 induced jobs would be created in the project area.

The Husky project is expected to require 1965 total man-years to construct, of which Husky expects 17 per cent or 335 man-years to be supplied locally. It estimated that 66 indirect jobs and 140 induced jobs would be generated during peak construction.

As indicated in Section 5 of the report, the Board believes that Husky has somewhat under-estimated the likely capital costs for its project. The Board also believes that the workforce required by Husky would be somewhat larger than projected in its application. Notwithstanding these adjustments, the Board anticipates slightly more local employment opportunities to be generated during the construction phase of the Shell project than would be generated by the Husky alternative. This is because the new "*greenfield*" plant proposed by Shell would be a larger construction project than Husky's proposal, where some facilities already exist.

Shell estimated that when the operating phase commences, 180 full-time jobs would be created. Of these, Shell anticipates that 75 would be hired locally. In addition to operative positions, Shell expected its operations to create 20 additional indirect jobs in local businesses and 135 induced jobs in the region. The total number of jobs created from operations is estimated by Shell to be 335.

Husky projected that 85 additional full-time jobs would be available at an expanded Ram River plant. Of these, Husky expected 50 to be filled by local residents. In addition to permanent operating jobs, Husky anticipated 18 indirect jobs and 71 induced jobs to be created in the region. The total number of jobs created from operations is thus expected to be 174.

The Board anticipates greater benefits to flow from the Shell proposal to the project area in terms of employment creation. While Shell's greater employment in both construction and operations is of greater benefit to the region, it should be noted that this is not an advantage in terms of economic efficiency.

The Board believes that the successful applicant should endeavour to hire locals where they are available and reasonably qualified. It is supportive of a suggestion by the Mountain View Group that the project operator should ensure that local high school students are aware of work opportunities and required training.

10.3.2 Regional Income

Both Shell and Husky anticipate their projects to substantially increase incomes and business opportunities in the region. In the construction phases of the projects, additional income would be injected into the region through expenditures on local labour and local purchases of goods and services. Total regional income from construction, representing the sum of net direct, indirect, and induced incomes from the projects are estimated to be \$36.7 million and \$37 million for the Shell and Husky projects, respectively.

The Board anticipates that regional income during construction would be higher under the Shell option as it entails slightly greater capital expenditures and would employ a larger construction workforce. The Board also expects differences in the distribution of this income within the project area. From evidence provided in both applications, the Board has estimated that for the Husky project a large portion of the regional income would be in the Rocky Mountain House area, while for the Shell proposal, there would be a more even distribution of income throughout the region.

Once operations commence, Husky anticipates total annual regional income from its project to be \$5.8 million while Shell expects an annual income of \$9 million to be generated in the area by its project. The Board agrees that annual regional income would be greater under the Shell project because of the larger operating workforce employed. Under the Husky proposal, the Board would again anticipate a higher concentration of annual regional income around the Rocky Mountain House area, while for the Shell project, the communities of Sundre and Caroline would receive a larger portion, and the communities of Olds, Innisfail, and Didsbury would also receive some income.

An additional factor which could bear upon the regional income from the competing projects is the expected timing. For the reasons set out in Section 5.3, the Board believes that for the Shell project, both the construction and the on-stream date for all its facilities would occur sooner than for the Husky project. This would mean that the regional income benefits

would be experienced earlier, a point mentioned as positive by a number of participants in the hearing. The Shell proposal would thus have this further advantage.

10.3.3 Municipal Taxes

There would be a benefit to the region under both the Shell and Husky proposals as new capital investment expands the tax base for municipal revenues. Husky estimated that \$2.74 million in additional annual taxes would be generated, nearly all of which would go to the MD of Clearwater. Shell expected to generate an additional \$2.8 million in taxes per year for the MD of Clearwater from its project and \$0.4 million per year for the County of Mountain View.

The Board recognizes that the Shell project holds a slight advantage in terms of extra municipal tax revenue generated, but the difference is small. Again, the distribution of taxes throughout the region would be wider and the payments would commence earlier for the Shell proposal.

10.3.4 Provincial Royalties

The development of the Caroline gas field would generate a significant amount of royalty revenue for the Province of Alberta. Shell estimated that over the life of its project, the province would receive approximately \$2 billion (undiscounted) in royalty revenue.

Husky estimated that its project would generate some \$1.035 billion in Crown royalty and \$0.456 billion in freehold royalty. It should be noted that the applicants used different price forecasts to estimate royalty revenues and, therefore, these numbers are not directly comparable.

The Board has evaluated both projects and determined that the Husky proposal yields slightly higher royalties for the same price scenario. The Husky project holds this advantage despite a higher estimate by the Board of plant capital costs, and assuming a 9-month delay relative to Shell because this project results in slightly lower deductions from revenues in lieu of Crown processing costs. However, the greater uncertainty with respect to the Husky cost estimates means that any royalty advantage would be eliminated if significant cost overruns occurred. The Board concludes that the preliminary nature of the Husky cost estimates and the accompanying uncertainty offset the slight royalty advantage and results in little difference between the projects.

10.3.5 Provincial and Federal Taxes

As well as providing benefits to the local project area, the Province of Alberta and the country as a whole would benefit from the tax revenues generated by either project. While no comparable estimates of federal and provincial taxes were provided by the applicants, the Board has estimated that, in present value terms, both provincial and federal taxes would be higher under the Shell project than under the Husky alternative. The Board's assumption of a 9-month delay in start-up of the Husky project from that stated in its application is mainly responsible for this result. Also, the smaller net benefit generated by the Husky proposal results in lower taxes paid to both levels of government.

10.4 Conclusions Respecting Socio-economic Impacts

The Shell project would result in major facilities being located in a relatively populated area, while the Husky project would locate some of the new facilities in more remote areas and at an existing gas plant. It is, therefore, not surprising that the Shell project would likely result in greater social impacts in

terms of noise, traffic, and other impacts on the lifestyle of residents of the area.

On the other hand, because the Shell project may involve modestly greater capital investment, would provide greater employment, and would likely commence both construction and operations sooner, on a present value basis it generally has an advantage in terms of providing additional regional income and taxes, and provides higher taxes to the provincial and federal governments. The Shell project, because of its location, would also result in a more even distribution of benefits throughout the entire region, although a significant portion of them would be centred in the general vicinity of the Caroline gas reserves. For the Husky proposal, the regional benefits would be generally centred in the Rocky Mountain House area.

The distribution of benefits within the region was an issue raised by a number of participants in the hearing. They stated that those people living in the vicinity of the gas reserves must put up with the negative environmental and nuisance effects and the potential risks associated with the field facilities, regardless of which processing project proceeds. Therefore they contended that the same region, near Caroline, should receive a significant portion of the benefits which might occur. They thus supported the Shell proposal. The Board does not consider such an argument overwhelming, but does see some merit in it and also a corresponding slight advantage to the Shell project.

Having regard for all of the socio-economic matters, the Board sees a modest overall advantage for the Shell proposal. It emphasizes, however, that either of the projects would be fully acceptable from a socio-economic viewpoint, provided all of the commitments made at the hearing were fulfilled.

At the hearing, Dr. Kostuch recommended that the successful applicant be required to develop a plan to evaluate the on-going social impacts and the success of the SEIA in predicting and mitigating such impacts. The recommendation was supported by CAB, PALSS, and others, and a variation of it was put forward by BLCOA. The Board believes the recommendation is a sound one and would make it a condition of any approval.

11 PUBLIC ACCEPTABILITY

11.1 Introduction

The extent to which the development of the Caroline reserves is generally acceptable to the public and the relative acceptability of the two respective projects proposed to recover the reserves were discussed at length at the hearing, and are factors that the Board believes it should consider.

In doing so, the Board attempted to assess the overall level of support from the general public on the basis of the evidence put forward by the members of the public that appeared at the hearing. Since it is not possible to know whether the positions presented were representative of general public sentiment, a precise assessment of this matter is difficult. It is further complicated by the uncertainty as to the criteria used by the various members of the public to establish their views respecting each particular project.

For the purposes of this section the Board has categorized the public, as represented by hearing participants, into three groups. These are local government, local business interests, and individual citizens. The local government group includes the various towns and municipal districts while the local business interests group includes individual business people and the various Chambers of Commerce.

The citizens group consists of individuals who appeared on their own behalf, and of organized groups who represented a number of individuals with generally similar interests. One citizen group, CAB, was somewhat unique in that its members were appointed by local governments in the project area. However, CAB indicated that it did not represent the local municipalities. All members of CAB are residents of the area and claimed they were speaking on behalf of a large number of other residents who were not at the hearing.

11.2 Local Government

Based on the evidence presented, the Board notes that there is unified support by the various local governments for the early development of the Caroline reserves. The governments differ, however, in their support for the specific projects.

Of those which stated a preference, the local governments generally supported the project which would be located physically nearest to them and therefore more likely to have greater positive economic impact on their community. At the hearing there was support from a larger number of local governments for the Shell project, presumably in part because the Shell proposal is located in an area that has a larger number of local governments.

11.3 Local Business Interests

Local business people, including the various Chambers of Commerce, expressed a great interest in the economic well-being of their communities. Therefore, like local governments, they strongly supported the early development of the Caroline reserves. They also generally showed support for the project which would be physically located nearest to or within their areas of influence. As there are more towns in proximity to the proposed Shell project, this led to greater support for that proposal.

A number of participants, in referring to the business community's support for the Shell project, made reference to a convoy, in the spring of 1989, organized by the Sundre and District Chamber of Commerce. The convoy attracted a large and varied number of participants which these interveners said was

an indication of strong support for the Shell project by the community and business interests in the area.

11.4 Individual Citizens

It is often difficult to draw conclusions respecting the overall views of citizens of an area based solely on the views of those who appear at a hearing. However, over 650 individuals either made submissions, signed them, or held membership in groups that appeared at the Caroline hearing. This is a considerable number given the population of the region. Additionally, CAB claimed to be speaking on behalf of a much larger group, the so-called "*silent majority*". Although this claim was challenged by other participants in the hearing, CAB members pointed to the lack of opposition to their re-appointment to the committee after municipal elections in 1989 as evidence of general community support for the position taken by CAB.

Having regard for the number of citizens who appeared or were represented at the hearing, the Board believes it has gained an impression respecting the overall views of the public in the area. In terms of developing the Caroline reserves, the Board notes that only a small portion of the public is opposed to any new development. These individuals cited environmental, safety, and other reasons for their opposition. The majority of people appeared to be either supportive of the development of the reserves, or at least prepared to accept the development recognizing that it is a very sizeable reserve from which many economic benefits could flow. The Board notes that the area residents wanted to be assured that the Caroline development would take place in a safe, environmentally and economically sound manner.

With respect to support for a specific project, most of the individuals who appeared or were represented expressed support for the Shell project, This was partly due to the large number who signed individual letters presented by Mr. Saunders. A principal reason given was that the gas reserves, and thus the necessary field facilities and possible negative impacts, were in the Caroline-Sundre area. Therefore, the plant and associated developments, with their related economic benefits, should be in the same area where the majority of people would have to accept the inconvenience of the development and the possible associated risks. There were also many expressions of trust that Shell would live up to its commitments to the local communities.

A number of individuals or their representatives favoured the Husky project, with much of the support expressed by people who owned property in the vicinity of the proposed Shell plant and other facilities, and who did not wish to receive the possible negative impacts of such a development. In supporting the Husky project, they generally pointed to the reduced total SO_2 emissions in the region as a significant environmental benefit, as well as to other environmental, safety, and economic reasons.

From the interventions presented, the Board notes that there is only a relatively small portion of people in the area who are opposed to the development of the Caroline reserves and therefore both projects. Furthermore, even with the various uncertainties and possible overlap of presentations, the Board believes that there is greater individual acceptance within the region for the Shell project than for the Husky project.

11.5 Route and Site Selection

The Board has treated route and site selection as being inherent in the consideration of the environmental, socio-economic, risk, public

safety, and public acceptability criteria, and also to some extent in operating reliability, economic efficiency, and future development criteria. In this section, the Board offers some comments on the process of route and site selection and community consultation by the applicants, and also deals with specific localized routing and siting issues raised by interveners.

The Board believes that the process of route and site selection and accompanying community consultation carried out by the applicants is very important. The selection of optimum routes and sites involves a balancing of many diverse private and public factors in a somewhat subjective fashion. Key aspects are the applicants' efforts to achieve an understanding of and to involve the community and recognize their needs in this balancing and the degree to which the community accepts the ultimate selection.

The Board notes that the applicants generally followed systematic approaches in their route and site selections, and made considerable efforts to provide for public consultation and input. The Board believes that this has resulted in the resolution of many issues and the alleviation of many concerns that would otherwise have been brought to the hearing or would remain as objections to the development.

The Board notes in particular the concerns expressed by CRAG and other interveners regarding the process used by Shell to select Site E as the proposed gas plant location. In general, the Board believes that the site selection decision-making process resulted in a reasonable compromise between a number of conflicting goals and objectives, and that these compromises are fairly reflected in the final site selected.

A number of specific suggestions regarding localized aspects of routing and siting were raised at the hearing. In reviewing these, the Board is conscious of the acceptance of the proposed routes and sites by many other persons who are also directly affected or have concerns, some of whom may not have appeared at the hearing. The Board recognizes that site changes at this time would shift or relocate the impacts, and likely result in concerns by others. Further, the Board believes that the site selection and public consultation processes used by the applicants have resulted in a great deal of consideration of possible alternatives. Thus the Board would not pursue a suggested relocation by requiring further studies and possibly re-opening the hearing, unless a suggested relocation appeared to have significant advantages and few obvious disadvantages.

The Board's view of the specific routing and siting suggestions is set out below.

- CRAG suggested that the north compressor station could be moved approximately 1 km to the west. The Board estimates that this would increase the distance from the nearest residence from about 1.6 km to about 2.4 km. This additional separation would not appear to be justified considering the additional clearing and disturbance that would result from relocation of the compressor site and connecting pipelines, and the possible risks to the Beaver Creek watershed. The Board believes that the proposed site, with a 1.6-km separation distance from residents, should not result in any significant impact on them. (The issue of emergency evacuation routes for the CRAG residents in the area is addressed in Section 9.2.3.)
- CRAG suggested that the proposed northern leg of the gathering system could be connected directly to the central leg and thus eliminate the pipeline and the north compressor which would be near some of the CRAG residents. The Board believes that this would result in much

greater volumes of sour gas being moved through a populated area. Also, it would result in the compressor having to be relocated to an area of greater resident density and hence impose a greater impact.

- CRAG suggested that Husky's gas transmission plant be relocated from Site E to the central compressor station site. The Board notes that this would result in Husky's plant and the sour gas transmission pipelines being closer to more residences and hence would not appear to be advantageous.
- The Brunners requested that the south compressor station be relocated farther away from their residence than the current 2-km separation distance. A 2-km separation from a facility such as a compressor station should not result in significant impacts. Further, the relocation of the compressor site would likely require rerouting of a substantial portion of the pipeline system which has gained the acceptance of the many other residents in the area.
- The proposed fresh water supply line from the James River to Shell's proposed gas plant would follow a route generally parallel to Amoco's proposed condensate line. The Board would require Shell, if its project proceeds, to consider the feasibility of installing both lines in the same ROW.

11.6 Conclusions Respecting Public Acceptability

The Board believes that the local governments and business interests are totally in support of development of the Caroline reserves. With the exception of the M.D. of Clearwater No. 99, which did not support either applicant, and those from Rocky Mountain House, the majority of the public support the Shell project over the Husky proposal. Even though there were some individuals who supported the Husky project, many of them appeared to do so primarily because they opposed certain aspects of Shell's project. The local citizens generally support the Shell proposal, and on an overall basis, the criteria of public acceptability appears to favour that project.

The degree of understanding and acceptance of the project by the public is partly as a result of the many efforts over the past several years to involve the public in the project planning. The Board commends these efforts and agrees with a number of interveners, notably CAB and PALSS, that public involvement should continue and should involve a cross-section of the public in the affected areas.

12 FUTURE RESOURCE DEVELOPMENT POTENTIAL

12.1 Introduction

The Board has before it specific applications from Shell and Husky to produce the Caroline gas reserves. Its focus must therefore be on these applications. At the same time, both of the applicants and a number of participants in the hearing provided evidence or commented on the ability of the Shell or Husky proposals to be integrated with future potential developments in the region. For this reason, and in order to carry out its mandate of promoting orderly and efficient development, the Board must assess the Shell and Husky proposals in relation to other possible future resource developments in the region. The Board has considered the following possible developments:

- Bearberry ultra-sour gas on a commercial scale,
- potential further sour gas discoveries in the Caroline area,
- available new gas and potential further discoveries in the foothills area served by the current Ram River plant,
- oil recovery enhancement by CO_2 flooding, and
- integration of sulphur recovery between plants.

12.2 Bearberry Ultra-sour Gas

The Bearberry field is located less than 15 km from Shell's proposed Caroline plant site and Shell has identified a suitable pipeline corridor between them. Shell has planned its Caroline plant to allow integration of Bearberry commercial production, which Shell believes could commence in less than 5 years. Shell would add oxygen-enrichment facilities to its sulphur plants to provide the required additional capacity. Shell indicated that this addition combined with some technical improvements and the recovery of the degassed sulphur vapours would potentially increase its plant's sulphur recovery level from 99.8 per cent to 99.9 per cent. Furthermore, Shell suggested that the nitrogen from the oxygen plant would be injected into the Bearberry wells to lift the sulphur solvent up the wellbore. Regeneration of the solvent to remove sulphur would take place at its proposed Caroline plant site.

Shell stated that the proximity of Bearberry to its proposed Caroline plant would reduce environmental and safety risks, and would avoid the need for solvent regeneration facilities in the field.

Husky believes that Bearberry commercial production is quite uncertain at this point and hence should not be a major factor in the consideration of the current plant applications. However, Husky indicated that from a technical point of view, Bearberry gas could be transported to and processed at its Ram River plant. It claimed that processing and sulphur capacity would become available as other supplies to the plant decline, or by increasing the level of oxygen enrichment.

The Board believes that there is sufficient probability for Bearberry commercial production to occur within an appropriate time frame that it should be considered in the assessment of the two proposals. In this regard, the Shell proposal would be considerably more suitable to accommodate the Bearberry gas without having to build a new plant in the area. The reasons for this are the shorter distance to the plant and thus the avoidance of a long-distance sour gas pipeline, and the likelihood of greater sulphur plant capacity being available because of the greater ability to introduce oxygen-enrichment.

12.3 Caroline Area Discovery Potential

There are a number of prospective oil and gas zones underlying the Caroline area. The deeper zones such as the Beaverhill Lake (Caroline) and the Leduc (Bearberry), are generally more sour and richer in liquids, and hence are the ones that would be of most significance to the current development proposals.

Shell stated that continued exploratory drilling for the Beaverhill Lake has not resulted in any new discoveries in the Caroline area. However, the Board believes that because a number of other formations such as the Wabamun, Nisku, and Leduc are gas bearing in the Caroline area, the potential for further highly sour gas discoveries does exist. The proposed Shell Caroline plant would provide higher sulphur recovery levels than do existing sulphur recovery plants in the area, and would be appropriately designed to handle new ultra-sour gas. It would also likely be more easily accessible to new gas reserves from the Caroline area than would an expanded Ram River plant.

12.4 Foothills Area Discovery Potential

Husky stated that its Ram River plant is currently under-utilized, particularly the sulphur recovery portion of the plant, and that the currently connected supplies would continue to decline in the future. Husky said that its Ram River plant could serve as a regional sulphur recovery plant for the large area in the foothills already served by its extensive existing pipeline network, along with Caroline and Bearberry. Husky pointed out that it is currently successfully transporting raw sour gas of up to 30 per cent H_2S from fields as far away as 100 km. Husky stated that it could successfully expand and operate its already large gathering and processing system. Husky provided estimates showing that 1992 production from currently connected fields of approximately 12 000 x 10^3 m^3/d, along with the 8000 x 10^3 m^3/d of proposed Caroline gas plus a maximum tie-in of 5600 x 10^3 m^3/d of other new already-discovered foothills gas, would essentially load an expanded Ram River plant. It added that future new discoveries of 800 x 10^3 m^3/d and the Bearberry gas could be accommodated as the currently connected supplies decline. Husky stated that new foothills gas alone would not increase the present low utilization of the sulphur recovery portion of the plant because of the relatively low H_2S content of this gas.

Shell expressed optimism about further gas discoveries in the Ram River foothills area, but provided limited quantitative information.

The Ram River plant and its gathering system are situated to serve a major segment of the foothills belt, and the Board believes it logical that this would continue to be its primary service area. The Board believes that there is significant potential for further gas discoveries within this area, because geological structures and reservoir zone thicknesses are considered favourable and the density of exploratory wells to date is very limited. The rate of gas development in this area can be expected to increase with improvements in gas and sulphur prices.

New gas discovered in the Ram River foothills area could be accommodated at an expanded Ram River plant more easily than at a new Shell plant in the Caroline area. However, such gas could also be processed at Husky's existing Ram River plant, perhaps more readily in terms of the availability of capacity than if the Caroline gas was also going to that plant. Additionally, the Board believes that new gas in the general Ram River area could facilitate upgrading of the sulphur recovery at the Ram River plant, even if it was not expanded in accordance with the current Husky application.

The Board is concerned about the Ram River plant alone being able to effectively provide capacity for all future sour gas processing needs for both its current large foothills gathering area, and the Caroline area including Bearberry. If foothills gas developments were to increase significantly, then future Bearberry gas or future sour gas discoveries in the Caroline area may still require a new plant, with some likelihood of lower sulphur recovery levels and higher sulphur emissions. Similarly if Bearberry gas production proved to be highly successful, then later foothills developments may require another new plant, again possibly with lower sulphur recoveries and higher emissions.

In summary, existing unconnected gas reserves or new discoveries in the general Ram River area appear to be quite promising and could be appropriately accommodated at an expanded Ram River plant. It is unlikely that the construction of a new plant in Caroline, as proposed by Shell, would preclude the handling of such gas at Ram River and indeed, could provide greater flexibility to handle such gas.

12.5 CO_2 Supply for Oil Recovery

Shell is currently operating an enhanced oil recovery scheme involving CO_2 injection in the Harmattan-Elkton oil reservoir. Shell stated that there is some possibility of a supply of CO_2 being needed for this purpose and that its proposed Caroline plant, located relatively nearby, could provide the required CO_2.

The Board understands that prospects for expansion or extension of the CO_2 injection scheme are uncertain and hence ascribes only a very limited advantage to the Shell proposal for this purpose.

12.6 Integration Between Plants

The Board believes that integration of sulphur recovery between nearby plants may be required in order to minimize or reduce SO_2 emissions in the general Caroline-Ram River area. Where one plant has, or proposes to install, higher levels of sulphur recovery and where others nearby have low levels or no sulphur recovery at all, it may be desirable to send the acid gas from the latter to the former.

Shell and Altana have submitted applications to transfer the acid gas from Altana's plant to Shell's proposed Caroline plant for recovery of the sulphur. Husky indicated that it would also be prepared to take the Altana gas to its Ram River plant.

The Board believes there is a potential for additional integration of this kind in the Caroline area. In particular, the Board intends to have Amoco examine the feasibility of transferring acid gas from both of its Caroline plants to either Shell's or Husky's project, whichever ultimately proceeds. The Board also suggests that Gulf, as operator of the Strachan plant, might consider integration possibilities in the future with Husky's Ram River plant.

In comparing the Shell and Husky applications with respect to this matter, the Board finds both projects equally capable, but notes that Shell already has arrangements in place for Altana's acid gas.

12.7 Conclusions Respecting Future Resource Development Potential

The Board sees merit in the placement of a new sulphur recovery plant in the Caroline area specifically to handle the large Caroline reserves and possibly Bearberry gas, and to leave the Ram River plant unencumbered to serve future new gas development near its large gathering area. The Board sees some possibility that the movement of new gas reserves to the Ram River plant may result in the upgrading of sulphur recovery at that plant, even in the case where it was not processing the Caroline gas.

Overall, as it relates to future development potential, the Board sees a distinct advantage in favour of the Shell proposal.

13 IMPACT OF RELATED APPLICATIONS

13.1 Introduction

The related applications considered in this section are those proposed to accommodate the various products from the plants or provide electrical power to the proposed projects. The applications are considered in two groups, associated applications and future applications. The associated applications are the Federated NGL pipeline proposals, the Amoco condensate pipeline proposals, and the proposals by Shell and Altana to deliver Altana's acid gas to Shell's proposed Caroline plant for sulphur recovery. These were considered for approval at the hearing, and the Board has evaluated them on the basis of technical soundness, environmental impacts, and landowner or occupant acceptability.

The future applications are the proposed NOVA gas installations and TransAlta power supply facilities. Recognizing that these facilities were not formally applied for and therefore could not be considered for approval at the hearing, the Board has only considered the possible effects of the facilities on the relative merits of the projects proposed by Shell and Husky.

13.2 Associated Applications

The Board finds the proposed facilities in the associated applications to be technically satisfactory. All landowners and occupants along the proposed pipeline routes of both the Federated Caroline Extension (Shell project) and the Federated Ram River Extension (Husky project) have consented to the routing and have no objection to the issuance of a permit. Also, the Board has not received any objections from landowners or occupants along the proposed routes of the Amoco condensate pipeline or the Shell acid gas pipeline.

The Federated pipeline for each project would be approximately 160 km in length as shown in **Figure 4**. Of the total length, approximately 100 km would be common to both applications. Both proposals would require a 15-m ROW with 3 m of temporary working space on cultivated land and additional ROW at river, road, and pipeline crossings. Both proposed routes would cross lands with moderately low to very low capacity for outdoor recreation. Although both proposed routes would cross key wildlife areas, neither would traverse site-specific habitat for rare, threatened, or endangered species. The proposed Federated Ram River Extension would cross two critical wildlife areas, while the proposed Federated Caroline Extension would not cross any. However, the crossings of critical wildlife areas are at locations where the proposed pipelines would be installed immediately adjacent to existing pipeline ROW. Both routes would cross fair to good ungulate habitat.

Of the total length of the proposed Federated Caroline Extension, 115 km or 73 per cent would follow existing linear development, quarter lines, or existing ROW compared to 127 km or 79 per cent of the proposed Federated Ram River Extension. Approximately 4 per cent of the proposed Federated Caroline Extension would be within the Green Area with the primary land use being cattle grazing. The rest of the route (96 per cent) would traverse the White Area, where land use includes cultivated land, hay land, improved pasture, bush, and bush pasture. The proposed Federated Ram River Extension would traverse the Green Area for approximately 12 per cent of its total length. The primary land use in this area is forestry. The remainder of the route (88 per cent) would traverse the White Area, with cultivated land, hay land, improved pasture, bush, and bush pasture as land uses. Although the proposed Federated Ram River Extension

would cross steeper terrain, the estimated capital costs are similar for both routes, at approximately $22 million.

Although the Federated applications differ in routing for approximately 60 km of their total length, the Board believes that the two proposals are very similar from an environmental perspective.

The proposed Amoco condensate pipelines would have the same routing for either the Husky or Shell projects, and would require a 15-m ROW for approximately 9 km through farm and grazing land, and a small amount of bush pasture. Amoco stated that it would explore a possible sharing of ROW with Shell's proposed construction camp water supply line from the James River if Shell's project is approved. If ROW sharing is possible, incremental impact of the proposed Amoco pipeline for the Shell project would be somewhat reduced.

The proposed Shell acid gas pipeline from the Altana gas plant to Shell's proposed Caroline gas plant at Site E would be approximately 2 km long. The associated compressor was applied for by Altana and would be installed at the Altana gas plant. Although Husky has not applied for a pipeline to transport acid gas from the existing Altana gas plant to Husky's proposed Site E gas transmission plant, arrangements have been made to accept the Altana acid gas at Husky's plant if its project is approved.

Due to the technical soundness, lack of opposition to the selected pipeline routes, and the relatively minor environmental impacts of these associated applications, the Board considers them to be acceptable. The Amoco condensate pipeline and the Altana acid gas pipeline proposals would follow the same route regardless of which project was to be approved. Even though there is some possibility of ROW sharing with Amoco in the Shell proposal, there are no significant differences between the Shell and Husky applications.

13.3 Future Applications

The NOVA Caroline proposal for the Shell project would consist of meter station facilities which the Board believes would include a short 250-m pipeline. All construction of the facilities would likely take place on unoccupied Crown land and would not involve any watercourse crossings. The estimated capital cost of the NOVA Caroline proposal is $1 550 000.

The NOVA Ram River proposal for the Husky project would require about 16 km of 660-mm OD lateral pipeline loop and meter station facilities. Regardless of which project is approved, the lateral loop and the meter station expansion will be required, although the pipeline would be down-sized to 508-mm OD if the Ram River gas plant is not approved to process the Caroline gas. The proposed pipeline would cross Vetch Creek and several other small unnamed watercourses, but the incremental environmental effects of a 660-mm OD pipeline as compared to a 508-mm OD pipeline are considered negligible. The estimated capital cost of the NOVA Ram River proposal is $3 490 000.

TransAlta has submitted preliminary proposals for the electrical power supply facilities much of which would be common for both the Husky and Shell projects. TransAlta, in order to supply this common service, would require an estimated 85 km of new 138-kV transmission line from the Benalto area and associated substation facilities.

With respect to the Husky project, TransAlta would build an estimated 40 km of additional transmission line and associated facilities, to

be brought in from the Strachan and Ricinus areas. It appears that most of this transmission line would follow existing linear developments.

Upon submission of the applications in their entirety, a technical review will be undertaken and specific environmental and landowner or occupant issues, if any, would be addressed.

Notwithstanding that the complete future applications have not been received for these facilities, the Board notes that the Shell proposal would likely involve 250 m of new pipeline construction, while the Husky proposal would involve laying larger pipe in a project that NOVA suggests will proceed in any case. The most significant difference is the requirement for 40 km of additional electrical transmission line for the Husky proposal. Overall, the Board believes this results in an advantage for the Shell project.

13.4 Conclusions Respecting Related Applications

The Board has determined that certain associated and future facilities are required in order to allow either the Husky or Shell projects to function in the most orderly and efficient manner. In addition, environmental and landowner or occupant concerns have not been identified as issues. The Board is therefore prepared to approve those associated applications which would relate to the approved project.

The Board believes that there are no significant differences between the associated applications or the future applications which would preclude or affect the approval of either the Shell or the Husky project.

14 OVERALL CONCLUSIONS RESPECTING THE CAROLINE BEAVERHILL LAKE GAS DEVELOPMENT APPLICATIONS

The conclusions set out in this section of the report have resulted from a full consideration of all of the evidence placed before the Board at the public hearing. That evidence and the reasons for the conclusions are summarized in the preceding sections.

14.1 The Acceptability of the Applications

The Caroline Beaverhill Lake Gas Pool is one of the most significant reserves of natural gas, hydrocarbon liquids, and sulphur that have been discovered in Alberta for many years. The production and marketing of these reserves would provide very substantial economic benefits to the general Caroline region, the province, the country, and the industry. These would include employment opportunities, expenditures for goods and services, and royalties and taxes to the various levels of government. To achieve these benefits, there is a need for a development project, such as the ones proposed by Shell and Husky.

Each of the proposed projects has been carefully designed to meet all relevant provincial standards and regulations. Their design is technically sound and the Board is confident they would meet operating reliability and resource conservation standards.

There would be negative impacts on the environment from either development proposal. However, with appropriate care in operations and adequate monitoring and follow-up mitigative actions, the impacts should not be of major significance or long lasting. There would also be some negative social impacts on the area and on the lifestyles of its residents. With good planning and continuing involvement of the affected public in that planning, the social impacts should not be overly disruptive.

Regardless of which of the proposals proceeds, there would be incremental risks to the safety of the public in the area due to the production, processing, and transportation of large volumes of natural gas containing some 35 per cent H_2S. The risks, although relatively low, would be real, but the special design features incorporated into the proposals, coupled with particular care in operations, should prevent any major accidents. In this regard, it will be important that all operating staff involved in potentially dangerous parts of the development be well trained and continuously aware of the need for care.

Since no guarantee against an accident can be given, a detailed well-designed emergency response plan must be in place, and the operating staff must be able to immediately implement the plan in the unlikely event of an accident. Public involvement will be important in the development of the details of the plan.

The related facilities to move natural gas and liquid hydrocarbons to market and to provide electric power are essential, whichever project proceeds, and would not have serious negative impacts.

Notwithstanding that some negative impacts on the region would result from the development, whether it be by Shell or by Husky, the Board believes that these impacts would be outweighed by the economic benefits which would be experienced. Proceeding with either one of the proposed developments would thus be in the public interest.

Whichever project proceeds, it would be subject to terms and conditions to ensure that

the benefits from the project would be forthcoming and that the negative impacts would be minimized and mitigated to the maximum practical extent.

14.2 A Comparison of the Proposals

Since there is need for only one project to develop the Caroline reserves, and since it has been concluded that either of the two proposed developments would be in the public interest, the Board has made a comparison of the two proposals. In doing so, it has had regard for the various issues which it believes, in this case, constitute suitable criteria by which the public interest can be evaluated. The criteria considered and the sections of the report in which they are discussed are as follows:

- economic efficiency . . . . (Section 5),
- technical feasibility and operating reliability . . . . . (Section 6),
- resource conservation . . . (Section 7),
- environmental impacts . . . (Section 8),
- risk to public safety . . . . (Section 9),
- socio-economic impacts . (Section 10),
- public acceptability . . . . (Section 11),
- future resource development potential . . (Section 12),
- impact of related applications . . . . (Section 13).

The Board has subdivided many of these criteria into a number of elements which it believes, when combined, give an overall measure of the particular matter. For example, environmental matters include atmospheric emissions, surface water, groundwater, wildlife, fish, vegetation, and soil.

To compare the proposed projects from a public interest viewpoint requires a detailed comparative evaluation of the proposals for each criterion. Not surprisingly, the Board found that each of the proposed projects enjoys an advantage over the other with respect to certain of the criteria or individual elements of a criterion. For some of the criteria, there was essentially no difference between the proposals. As a result, the Board has had to make an overall comparison on the basis of all of the criteria combined, giving appropriate weight to the importance of each element of the public interest.

The Board does not believe that either the comparative evaluation of individual criterion, or the weighting of them, can be carried out in a precise quantitative manner. It has therefore not done so and has made its assessment in a qualitative manner.

Those criteria which reflect the economic efficiency and benefits of the development to society are important ones and deserving of substantial weight in the overall assessment. In the Board's view, the Shell proposal would be most in the public interest with respect to these criteria. This is primarily because the Board does not accept that the capital costs of the Husky proposal would be as low as estimated by Husky, and therefore significantly less than for the Shell proposal. Also, the Board believes that the lack of Owner support and the relatively limited amount of engineering design work currently completed for the Husky project, would result in the start-up for that project being at least 6 to 12 months later than for the Shell project. This delay would affect the present value of the Husky project and result in the Shell project having a slightly higher total present value. For the same reason, the Shell project would provide, in present value terms, marginally greater regional income and taxes to the various levels of government.

Additionally, the Board believes that for the Shell project, there would be a better distribution of the economic benefits through-

out the general region of the development. The Board generally agrees with the view of several participants in the hearing, that those people who live in the immediate vicinity of the gas field and thus are subjected to its negative impacts, should share equitably in the economic benefits which would result from the development. The Board has long been of the view that one of the reasons for opposition to energy developments by the public is that, too often, those directly and adversely affected by a project do not perceive themselves as appropriately sharing in the benefits from the project.

The Board believes the more important remaining criteria are the social impacts of the development, the risk to public safety, and impacts that would occur to the natural environment.

Regarding social impacts, the Board believes the Husky project would be preferable to that proposed by Shell with respect to traffic problems, increased noise, visual impacts, and negative impacts on property values in the area. This results because the Shell project would involve more facilities in relatively populated areas while the Husky project would locate some of the new facilities in a relatively remote area. However, since the Husky project would be identical to Shell's in terms of the wells and gathering system, and would also have a plant, although a smaller one, at the Shell gas plant site, the advantage to the Husky proposal is small.

For essentially the same reason, the Board sees no significant difference between the projects in terms of other social impact elements including odours and fugitive emissions, the need for community infrastructure, conflicts with existing land use, effects on the health of residents in the area, and changes to their lifestyles.

Overall, with respect to these social impacts, the Board sees little difference between the projects, but Husky has a small advantage.

The safety of the public is an important element of the public interest. The Husky project would involve additional lengthy sour gas transmission pipelines, but otherwise would be similar to Shell's in terms of risk to public safety. The risks associated with these transmission pipelines would not be great, an increase of perhaps some 10 to 20 per cent over those of the Shell project, primarily because the sour gas transmission pipelines would be largely located in relatively remote areas. However, this risk is incremental and thus the Shell proposal would have an advantage.

With respect to an emergency response plan, Shell's proposal would be preferable, involving only one operator and fewer control centres. The need for excellent co-ordination of separate response plans would represent a potential source of concern if the Husky project were to proceed.

Overall, in terms of public safety, the Board believes that the Shell project would have an advantage.

The natural environment is also an important element of the public interest. In this particular case, the Board has assessed environmental impacts by considering a number of important biophysical issues. One of these is the emissions of SO_2 to the atmosphere, and it is respecting this matter that the Husky project has its most significant advantage over that proposed by Shell. The Husky project would increase the sulphur recovery at the Ram River plant to accommodate the Caroline reserves, and the higher sulphur recovery would also be applicable to the other gas reserves currently supplying the Ram River plant. The total SO_2

emissions in the general region would thus be significantly reduced.

The reduction of total sulphur emissions to the atmosphere is desirable, but it is important to note that the Board does not agree with some of the interveners that current emission levels represent a risk to human health or livestock in the region. Furthermore, the Board does not agree with one of the interveners that on the basis of the evidence presented at the hearing, trees in the region are already being seriously affected because of sulphur emissions. The exception to this is in the immediate vicinity of the Ram River plant where sulphur dusting and SO_2 from sulphur block fires have caused damage to local vegetation. Processing of the Caroline gas at the Ram River plant could make the mitigation of these existing problems more difficult. This would tend to offset the possible benefits associated with the lower sulphur emissions resulting from the Husky project.

The Board also notes that the evidence at the hearing regarding damage to trees referred to an area relatively close to and downwind of the Ram River plant. The Husky proposal, although it would mean lower total sulphur emissions in the broad region, would not mean lower cumulative sulphur emissions from Husky's facility over the extended life of the Ram River plant. As a result, if tree damage is indeed occurring in the area identified at the hearing, proceeding with the Husky proposal might not alleviate this situation.

The Board is also of the view, as indicated later in this section, that potential future resource developments in the general Caroline-Rocky Mountain House region could further offset the advantage the Husky proposal has in terms of sulphur emissions.

Referring to other environmental aspects, the Board sees a modest advantage for the Shell proposal with respect to impacts on groundwater, wildlife, and soil, and in terms of emissions of oxides of nitrogen. It sees no discernible difference regarding impacts on surface water, fish, and vegetation, or in terms of CO_2 emissions.

Overall, although the Board recognizes the value of the lower regional sulphur emissions which would result from the Husky project, this advantage is offset by a number of other considerations. As a result, in the Board's judgement, the Husky project is only modestly preferable to that of Shell's in terms of the environment.

The remaining criteria also played a significant although smaller role in the Board's evaluation. In terms of resource conservation, the Board believes there would be little difference between the projects regarding the ultimate resource recovery or the energy used in transporting the produced sulphur to market. The Husky proposal would consume less energy in its plant operations than would Shell's, because it would involve oxygen-enrichment technology. Although this would be offset if Shell adopted the same technology, as it said it planned to do in future, it does result in an advantage for the Husky project.

The technical feasibility and operating reliability of a project are also important, and indeed, problems in these areas can increase risks to the public, cause impacts on the environment, and reduce the economic efficiency of a project. Either project would be acceptable from a technical feasibility and operating reliability viewpoint. However, the Board believes the Shell proposal would be more desirable because of the need for fewer facilities which would be located relatively closer together, Shell would use all new facilities as compared to the retrofitting of existing facilities as proposed by Husky, and the use by Husky of oxygen-enrichment technology on a very large scale.

The Board believes there is considerable potential for further resource development in the general Caroline and Ram River foothills region. In this regard, it agrees with Shell that there is a reasonable likelihood that the Bearberry ultra-sour gas reserves will be developed in the foreseeable future. The Shell proposal would be designed, in part, to accommodate these reserves and avoid the possible future need for another gas plant in the area. Although the Husky project could probably handle the Bearberry gas, it would not be as effective and efficient in that regard. For example, there is a fair chance that processing the Bearberry gas in the proposed Shell plant could involve a higher sulphur recovery than would be feasible at Ram River. This would offset the Husky advantage of lower sulphur emissions.

At present there are existing unconnected sour gas reserves in the region and the Board believes that additional sour gas will likely be discovered in the future. The existing Ram River plant is a logical place for processing many of these reserves. Although an expanded Ram River plant processing the Caroline gas could potentially accommodate this other gas, a lack of capacity might require another expansion at Ram River or a new plant in the area. The Board also notes that sufficient new gas going to Ram River could bring about an increase in sulphur recovery at that plant, even without the Caroline gas. Again, this would offset the Husky advantage of lower sulphur emissions.

The Board concludes that the development of a new plant in the Caroline area, as proposed by Shell, would have a clear advantage in terms of planning for future resource development in the region.

Many members of the public participated directly in the hearing, either individually or through group submissions. On the basis of those submissions, the Board has concluded that there appears to be more support in the general area for the Shell project than for Husky's proposal.

Either project would require related facilities to move natural gas and liquid hydrocarbons to markets and to supply electric power. There would be no significant difference in the effects of these related facilities on the respective projects.

In summary with respect to all the public interest criteria, the Husky project appears preferrable in terms of the environment, certain social impacts, and resource conservation. The Shell proposal has advantages in terms of economic efficiency and economic benefits, and likely regarding public acceptability. Shell also has an advantage regarding risks to public safety, technical feasibility and operating reliability, and future resource development potential. Having regard for all of these, the Board concludes that while both proposals would offer substantial benefits, the Shell proposal is the most desirable in terms of the overall public interest. Additionally, it is the preferred choice of the large majority of working interest owners.

Many participants at the hearing made reference to the Board's policy on gas plant proliferation. Both applicants argued that their proposed development would be consistent with the Board's objectives of avoiding the construction of new facilities to support the needs for processing new reserves in an economic and orderly fashion.

The Board is satisfied that approval of Shell's project is consistent with the Board's objectives for encouraging greater regional processing and use of larger facilities. The Board believes that the existing and expected gas reserve base in the general Caroline and

Ram River foothills region would be sufficient to support the long-term use of more than one large plant in the area and would permit the processing of all sour gas reserves at the highest level of sulphur recovery efficiency. The Board's policy on plant proliferation is not intended to direct that gas be processed at a single central facility over an area beyond prudent bounds, or to disregard the varied interests involved in orderly development. New development should strike a sound balance between public and private interests, and the Board believes that Shell's project does strike such a balance.

15 DECISION

The Board, subject to receipt of the necessary approvals from the Minister of the Environment with respect to environmental matters, hereby approves Applications No. 890969, 891504, 891505, 891506, 891478, 891479, 891480, 891481, 891482, 891568, 891569, 891570, 891571, and 900404 submitted by Shell Canada Limited, Application No. 891483 submitted by Federated Pipe Lines Ltd., Application No. 891290 submitted by Amoco Canada Petroleum Company Ltd., and Application No. 900236 submitted by Altana Exploration Company. These applications constitute the Shell project and their approval would be subject to the conditions described in Appendix A.

DATED at Calgary, Alberta on 31 August 1990

ENERGY RESOURCES CONSERVATION BOARD

G.J. DeSorcy, P.Eng.
Chairman

B.F. Bietz, Ph.D.
Board Member

F.J. Mink, P.Eng.
Board Member

APPENDIX A

Terms, Conditions, and Provisions of Approvals

1. Adherence to all of the applicable standards and requirements for oil and gas facilities in the province of Alberta.
2. Discharge of all of the undertakings included in the applications or given by the applicants at the hearing.
3. Achieve an annual average sulphur recovery level of 99.8 per cent and a minimum quarterly average recovery of 99.5 per cent.
4. The following special requirements which arise from the hearing and this decision:
    - The effectiveness of the leak detection systems proposed by Shell must be monitored and reported on to the Board.
    - Shell must provide the Board, in its Part II gas plant application, further details respecting its planned sweet gas purge systems.
    - Shell will be requested to further review the energy efficiency, economic, and operating reliability aspects of utilizing oxygen-enrichment technology at its plant to process the Caroline reserves, and submit its findings to the Board.
    - All facilities must meet or exceed the noise control guidelines of ERCB Interim Directive *ID 88-1*.
    - Shell must consider the feasibility of placing its fresh water supply line from the James River in the same right of way as planned for the Amoco condensate pipeline.
    - Detailed designs must be completed for all pipeline stream crossings and are to be submitted to Alberta Environment and the Board for review prior to construction.
    - Hydrogeological and other related studies must be conducted by Shell at the proposed Shantz sulphur forming site. A detailed design must be completed which will ensure adequate protection for surface and groundwater and is to be submitted to Alberta Environment and the Board for review prior to construction.
    - Shell must complete a satisfactory detailed emergency response plan and submit it to the Board for approval. The plan must include involvement of the public in its preparation, preferably through an Emergency Response Awareness Committee which would include representatives of a broad cross-section of the public in the affected area. The plan must address the problem of single road access, an appropriate warning system for Burnstick Lake residents, and the provision of monitoring equipment and an early alert system for the Brunner residence. The plan must cover a zone with a radius of 4 km, but also include the nearby population centres of Sundre, Burnstick Lake, and the Westward Ho area. The plan must also include a further 4-km awareness zone. The response plan must include an ignition policy accep-table to the Board with respect to a possible uncontrolled flow from a well.
    - A background and operations-related monitoring program acceptable to the Board must be developed through discussions between Shell, representatives of the affected public, Alberta Environment, and the Board. Monitoring in accordance with the program must be carried out and the results must be made public. The monitoring program should also include the gathering by Shell of detailed meteorological data for the area.
    - Shell must develop, with appropriate input from government departments, a program to accomplish the committed

to no-net-loss policy with respect to wildlife and fish habitat. Periodic reporting must take place respecting the success in implementing the program. Consideration should be given, in concert with appropriate government departments, to a program to gather baseline data of wildlife species in the area of the project.

- Shell must work with local communities to ensure the availability of adequate social infrastructure for health, security, and other services.
- Shell must endeavour to employ local residents and also establish communication links with local high schools to ensure they are aware of work opportunities and required training.
- Involvement with the public in the area must continue to ensure the public is aware of Shell's on-going plans. Also, a system for registering concerns and complaints, and for effective investigation of them, must be in place.
- Efforts should be made by Shell to schedule work shifts and other activities in a manner which would minimize potential conflict with school bus schedules.
- A program should be developed by Shell to provide an on-going audit of the success of the EIA and the SEIA in predicting impacts, and the effectiveness of on-going activities to mitigate those impacts.

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ENERGY RESOURCES CONSERVATION BOARD
Calgary, Alberta

GULF CANADA RESOURCES LIMITED
COMPULSORY POOLING
FENN-BIG VALLEY FIELD

Decision D 90-9
Application 900374

1 INTRODUCTION

1.1 Application

Gulf Canada Resources Limited (Gulf) applied, pursuant to section 72 of the Oil and Gas Conservation Act (the Act), for six compulsory pooling orders that would combine all of the tracts within each of six gas drilling spacing units (DSU) as a unit to permit the production of gas from all formations to the base of the Belly River Formation through wells currently existing in each of the DSUs.

The six DSUs and their relevant gas wells are as follows:

1 DSU: section 14 of township 35, range 20, west of the 4th meridian (section 14)

WELL: GULF FENN BIG VALLEY 11-14-35-20 (11-14 well)

2 DSU: section 27 of township 35, range 20, west of the 4th meridian (section 27-35)

WELL: GULF FENN BIG VALLEY 7-27-35-20 (7-27 well)

3 DSU: section 10 of township 36, range 20, west of the 4th meridian (section 10)

WELL: GULF FENN BIG VALLEY 6-10-36-20 (6-10 well)

4 DSU: section 15 of township 36, range 20, west of the 4th meridian (section 15)

WELL: GULF FENN BIG VALLEY 16-15-36-20 (16-15 well)

5 DSU: section 24 of township 36, range 20, west of the 4th meridian (section 24)

WELL: GULF FENN BIG VALLEY 10-24-36-20 (10-24 well)

6 DSU: section 27 of township 36, range 20, west of the 4th meridian (section 27-36)

WELL: GULF FENN BIG VALLEY 9-27-36-20 (9-27 well)

Gulf stated that all of the relevant wells are drilled within their respective DSUs and are capable of gas production.

Gulf proposed to allocate costs and revenues associated with gas production from the DSUs through their relevant wells on an areal basis and requested that it be appointed operator for each of the wells.

1.2 Interventions

The Board received one formal intervention to the application.

Shaman Energy Corporation filed a detailed intervention which will be addressed throughout this report.

Mr. Bob Collins registered for the hearing and stated for the record that he was the mineral interest owner of the northeast quarter of section 27-36 and was in favour of a Board-issued pooling order; Mr. Brent Mailer also registered for the hearing but did not otherwise participate.

1.3 Hearing

The application was heard on 4 and 5 July 1990 at a public hearing in Calgary, before a Board panel comprised of E. J. Morin, P.Eng., B. F. Bietz, Ph.D., and M. J. Bruni. The following table lists the participants at the hearing.

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Gulf Canada Resources Limited (Gulf) G. B. Scott	B. M. McClure, P.Eng. R. L. Long, P.Eng. F. R. Tener H. D. Zschach, P.Geol.
Shaman Energy Corporation (Shaman) P. B. Budd	W. J. Hartman, P.Eng. D. G. Knudtson P. E. Lemire D. F. Minken, P.Geol. E. A. Pavan, P.Eng.
Mr. Bob Collins B. J. Vanden Brink	B. Collins
Mr. Brent Mailer	
Energy Resources Conservation Board staff R. D. Heggie L. J. Hettinga, P.Geol. V. J. Vogt	

2 ISSUES

The Board considers the issues to be

- the need for compulsory pooling orders,
- the issuance of a pooling order for section 27-35 for production through the 7-27 well,
- the designation of the formations to be pooled, and
- the actual costs of drilling.

3 CONSIDERATION OF THE APPLICATION

3.1 Views of Gulf

Gulf identified the tract ownership of the six DSUs as follows:

	DSU	LEGAL DESCRIPTION	MINERAL HOLDER	PER CENT OWNERSHIP: OF TRACT	PER CENT OWNERSHIP: OF DSU
1	Section 14	North half, southeast quarter, and legal subdivision 3	Gulf	100	81.25
		Legal subdivisions 4, 5, and 6	Shaman	100	18.75
2	Section 27-35	East half	Gulf	100	50
		West half	Shaman	100	50
3	Section 10	West half and legal subdivisions 1, 2, 7, and 16	Gulf	100	75
		Legal subdivisions 8, 9, 10, and 15	Shaman	100	25
4	Section 15	East half	Gulf	100	50
		Northwest quarter	Shaman	100	25
		Southwest quarter	Czar Resources Ltd.	100	25
5	Section 24	East half, legal subdivisions 12 and 13	Gulf	100	62.5
		Legal subdivisions 4 and 5	Shaman and Universal Explorations Ltd.	80 20	10 2.5

		Legal subdivisions 11 and 14	Czar Resources Ltd.	100	12.50
		Legal subdivisions 3 and 6	Shaman	100	12.50
6	Section 27-36	South half and northeast quarter	Gulf	100	75
		Northwest quarter	Shaman	100	25

Gulf stated that it has been unable to acquire a mineral sharing agreement from Shaman in any of the six DSUs; therefore, there is a need for Board orders that would allow gas production to commence through each of the subject wells.

Gulf maintained that all of the wells are drilled within their respective DSUs and are capable of gas production from at least the Belly River formation. Gulf included the 7-27 well in this list of wells capable of gas production from the Belly River. Gulf was aware that Shaman disputed the ability of the 7-27 well to produce gas from the Belly River but disagreed with Shaman's position. Gulf stated that the 7-27 well was currently producing gas from a deeper zone, but was confident that a dual completion of the well would be successful in allowing effective and efficient Belly River gas production.

Gulf stated that while it has agreements in principle, it does not have signed mineral sharing agreements with Universal Explorations Ltd. (Universal) or Czar Resources Ltd. (Czar), and would expect them to also be subject to any Board-issued pooling orders. Gulf added that the six DSUs are being drained, or have the potential to be drained, by offsetting producing wells.

Gulf stated that it believed pooling orders issued by the Board in the subject matter should name the producing formation as all formations from the surface to the base of the Belly River. Gulf stated that this wording is typical in many of the voluntary mineral sharing agreements it has with other operators in the area, including Shaman. Gulf also maintained that there may be some potential gas-bearing sands up-hole that may become economic in the future, and Gulf believed that it would be administratively simpler to pool all of the common gas rights at once so that these would not become an issue in the future.

Gulf maintained that all tract owners, including Shaman, should be responsible for their share of drilling and completion costs. Gulf stated that of the six wells drilled within the subject DSUs, four were drilled for less than anticipated cost, one was drilled for slightly more than the anticipated cost, and the final well, the 7-27 well, was drilled for production from a deeper zone, but Gulf proposed to allocate only one-third of the total drilling costs of the well for the purposes of Belly River gas production.

Gulf also believed that all of the monies it spent on completing the wells in the various formations were relevant costs but, prior to the hearing, voluntarily agreed to remove certain completion costs for five of the six wells for formations that Shaman considered non-commercial.

Gulf stated it did this in an attempt to procure voluntary mineral sharing agreements from Shaman, even though it believed all of the completion costs for all of the wells were justified and should be shared by the relevant tract owners in each of the DSUs.

In accordance with the Board's pooling legislation, Gulf also requested that the Board impose a penalty equal to one-half a tract owner's share of drilling and completion costs, if that tract owner does not pay those costs within 30 days of being notified. Gulf believed that the imposition of the penalty was justified for three reasons: it has taken all of the risks associated with drilling the six wells, it has had its drilling money invested for a considerable length of time without realizing any return, and it has suffered some drainage of the lands by not being able to put its wells on production in a timely manner.

Finally, Gulf did not object to a request by Shaman to have immediate payouts, once production from the subject wells commenced, that would cover Shaman's royalty payments within its respective tracts of the DSUs pooled.

3.2 Views of Shaman

Shaman stated that it was unwilling to enter into any voluntary mineral sharing agreement with Gulf in five of the six DSUs because it disagreed with paying its share of what it considered excessive well costs expended by Gulf to drill the five wells through which gas reserves from the DSUs would be produced; however, Shaman added that it was not opposed to the concept of the Board issuing pooling orders for those five DSUs. In the remaining DSU, section 27-35, Shaman stated that it was opposed to any mineral sharing agreement that would allow production to commence through the 7-27 well. Shaman maintained that the 7-27 well was incapable of efficient and effective gas production from the Belly River formation and proposed that it would drill a new well in section 27-35 that would be a better and less expensive candidate for Belly River gas production.

For those five DSUs in which it had no objection to pooling orders being issued, Shaman was not opposed to the allocation of costs and revenues on an areal basis or Gulf being named the operator of the relevant wells. However, Shaman did object to Board orders that would name the producing formations as all formations to the base of the Belly River. Shaman contended that the Board should name only those formations in the order that Shaman considered capable of what it called commercial production. Shaman maintained that it should not have to be responsible for well costs attributed to what it considered non-commercial formations. Shaman added that if the Board believed it appropriate to issue orders for those formations that it considered non-commercial, then it proposed that the Board issue multiple orders for the relevant wells and name individual producing formations in each.

Shaman stated that it was not opposed to paying its share of drilling and completion costs, but it was opposed to paying its attributable share of what it considered excessive drilling and completion costs expended by Gulf. Shaman maintained that had it drilled any of the wells, it would have done so at substantially less than Gulf's costs. Shaman proposed that for purposes of any Board-issued pooling orders, the applicable well drilling and completion costs should be set at approximately \$170 000, a well cost average that Shaman submitted it had experienced for comparable Belly River gas wells in the area.

Shaman did not believe it appropriate that a penalty as outlined in the Board's pooling legislation should be applied to its share of drilling and completion costs. Shaman believed that the penalty was inappropriate because Gulf's well costs were already 150 per cent greater than if it had drilled the wells.

Finally, Shaman stated that it believed Board policy was to allocate 20 per cent of production revenue immediately upon commencement of production from the well to tract owners in order to allow them to pay their share of royalties for the applicable leases involved in the respective DSU. Shaman stated that royalty payments on its respective tracts sometimes exceeded this 20 per cent immediate payout, and thus requested an immediate payout equal to its royalty payments in each of its tracts within the subject DSUs.

3.3 Views of the Board

The Board heard evidence from both Gulf and Shaman on their inability to reach any voluntary mineral sharing agreement within the subject lands, primarily because of their dispute over applicable and relevant drilling and completion costs. Except for these differences, and the suitability of the 7-27 well for production from the Belly River, Gulf and Shaman agreed on the need for pooling. Accordingly, the Board believes there is a need to issue pooling orders that would allow production to commence through the subject wells.

Shaman questioned the capability of the 7-27 well to produce effectively and efficiently from the Belly River; however, the Board does not believe that Shaman proved to its satisfaction that the 7-27 could not produce from the Belly River formation. Although not conclusive, the Board notes that Gulf has successfully tested the 7-27 well at rates that compare favourably with the other five Basal Belly River wells. Shaman offered to drill a replacement well in section 27-35, but the Board concludes that drilling costs, inherent risks in drilling a new well, and the further disturbance to the surface land use in the area would not justify the drilling of a new well when there appears to be an existing well capable of Belly River gas production. For these reasons, the Board is prepared to issue a compulsory pooling order that would allow production to commence through the 7-27 well.

The Board concludes from the evidence, and the lack of objection, that Gulf should be named the operator of the subject wells in any orders issued by the Board, and that the allocation of costs and revenues to tracts within each DSU should be on an areal basis.

In naming the applicable producing formations in any pooling order, the Board believes that it has legislated authority to name only those formations that have been shown to require compulsory pooling and are believed to be capable or being made capable of commercial production. In that regard, the Board is not willing to name the producing formation as all formations from the surface to the base of the Belly River as suggested by Gulf. The Board does believe that sufficient evidence was presented to allow it to conclude that the Basal Belly River sand, some Belly River sands above the Basal Belly River sand and the Edmonton sand are all formations potentially capable of production. On this basis, the Board, from Gulf's evidence, is prepared to issue orders for sections 10, 14, and 24 that would name the producing formations as the Basal Belly River sand and other Belly River sands above the Basal Belly River; for sections

27-35 and 27-36 that would name the producing formation as the Basal Belly River sand; and for section 15 that would name the producing formations as the Basal Belly River sand and the Edmonton sand.

In determining drilling costs applicable to its pooling orders, the Board must have regard to section 75, subsection (1) of the Act which defines the cost of drilling a well as "...the actual cost of...drilling the well to, and completing it in, the formation named in the order...." The Board also believes it has an obligation to have regard for the drilling practices of any company involved in a compulsory pooling situation to ensure that the Board's regulations are followed during the drilling operations. Both Gulf and Shaman agreed that in making its decision on drilling costs, the Board need only identify the components of those costs, or the broad principles to be followed, and not undertake a detailed determination of the dollar amount owed by one party to the other. In this situation, the Board is satisfied that the differences that appear to exist between the monies expended by Gulf and Shaman for similar Belly River gas wells in the area are strictly a result of differences in operating practices between the two companies. Because of this, the Board concludes that applicable well costs for all but the 7-27 well should be those actual costs incurred by Gulf to drill the well to and complete it in each of the formations named in the pooling orders.

The Board also believes that an implication exists within its pooling legislation that a formation must go on production before the well costs for that formation are required to be paid by tract owners. In this regard, the Board believes that the well costs upon the commencement of production should include those drilling and completion costs only to each of the initial producing formations. In the event that another formation goes on commercial production at some future date, then the Board believes that Gulf would be obligated to wait until that time to recover any completion and drilling costs for the other zone from the tract owners in the DSU. In this way, if additional formations go on production that Shaman, or any other tract owner, consider non-commercial, they can decide at that future date to pay those completion and drilling costs for that zone immediately, or elect to have their share of costs come out of their share of production from that specific formation.

As for the 7-27 well, the Board notes from Gulf's evidence that it was drilled for the purpose of evaluating formations below the Basal Belly River. Therefore a benefit will be realized if the 7-27 well can be made capable of Belly River production and the cost of drilling a new well avoided. If Shaman were to fully compensate Gulf (on an acreage basis) for this avoided cost, then a windfall would accrue to Gulf since the costs Gulf incurred for drilling the 7-27 well were clearly for a different purpose than to evaluate and produce the Belly River. On the other hand, if Gulf received no compensation from Shaman, then Shaman would enjoy a windfall by acquiring an interest in a drilled well at no cost. Under these circumstances the Board believes it appropriate that Shaman and Gulf share equally in this potential benefit by first discounting the avoided cost by one-half and then Shaman compensating Gulf, on an acreage basis, for that discounted cost. The avoided cost is what it would have cost Gulf to drill a well to the Belly River if the 7-27 well were not available. That cost can be estimated with sufficient accuracy by averaging Gulf's actual costs, less any extraordinary expenses, for the other five Belly River wells referred to in this report. Basing this estimate on Gulf's costs is appropriate as Gulf would most likely have drilled a well to the Belly River if the 7-27 well had not been available.

The Board notes that Gulf took all of the risk in drilling the wells and therefore agrees with Gulf that it is appropriate to apply a penalty to a tract owner's share of drilling and completion costs if that tract owner does not pay its share of the costs within 30 days of being notified of such costs, and providing a pooling order has been issued by the Board and the subject well begins producing to its market. The Board is aware that as of 6 July 1990, the maximum penalty pursuant to section 72, subsection (5) of the Act was raised to 2 times a tract's share of drilling and completion costs from one-half a tract's share. However, for the subject application the Board believes it appropriate to apply the maximum penalty provision that existed at the time the application was heard which was a penalty not to exceed one-half times a tract's share of drilling and completion costs.

The Board believes that the penalty would apply to the drilling and completion costs relevant to each of the producing formations. Should Gulf elect at some future date to commence production from a further formation named in any of the orders, then the penalty against the completion and any further drilling costs attributed to that formation would only come into play at the time the other formation was to commence production to its market. The tract owners again would have the option of paying their costs within 30 days and would not incur the penalty.

Finally, the Board notes a request by Shaman to have orders that would allow revenue to come to it through the production from the subject well sufficient to cover its royalty payments in the DSUs. In the absence of objection from Gulf, the Board is prepared to issue orders that would reflect this.

4 DECISION

The Board, subject to the approval of the Lieutenant Governor in Council, is prepared to issue orders, pursuant to section 72 of the Act, designating that

- all tracts within section 14 of township 35, range 20, west of the 4th meridian be operated as a unit to permit the production of gas from the Basal Belly River sand and other Belly River sands above the Basal Belly River sand through the well, GULF FENN BIG VALLEY 11-14-35-20;

- all tracts within section 27 of township 35, range 20, west of the 4th meridian be operated as a unit to permit the production of gas from the Basal Belly River sand through the well, GULF FENN BIG VALLEY 7-27-35-20;

- all tracts within section 10 of township 36, range 20, west of the 4th meridian be operated as a unit to permit the production of gas from the Basal Belly River sand and other Belly River sands above the Basal Belly River sand through the well, GULF FENN BIG VALLEY 6-10-36-20;

- all tracts within section 15 of township 36, range 20, west of the 4th meridian be operated as a unit to permit the production of gas from the Basal Belly River sand and the Edmonton sand through the well, GULF FENN BIG VALLEY 16-15-36-20;

- all tracts within section 24 of township 36, range 20, west of the 4th meridian be operated as a unit to permit the production of gas from the Basal Belly River sand and other Belly River sands above the Basal Belly River sand through the well, GULF FENN BIG VALLEY 10-24-36-20;

- all tracts within section 27 of township 36, range 20 west of the 4th meridian be operated as a unit to permit the production of gas from the Basal Belly River sand through the well, GULF FENN BIG VALLEY 9-27-36-20;

- the actual costs of drilling and completing each of the wells named in the pooling orders be determined as described in section 3.3 of this report;

- Gulf Canada Resources Limited be designated as the operator of all the wells and be responsible for all completion, production, and abandonment operations at the wells;

- the allocation of costs and revenues associated with drilling, completing, operating, or abandoning the wells be on an areal basis, with each tract's share being in the same proportion as the area of each tract is to the total area of its respective drilling spacing unit; and

- if an owner of a tract fails to pay its share of drilling and completion costs within 30 days of receipt of the statement of costs then a penalty equal to 1/2 its tract's share of the unpaid amount be applied against that tract owner's share of drilling and completion costs.

DATED at Calgary, Alberta, on 24 August 1990.

ENERGY RESOURCES CONSERVATION BOARD

E. J. Morin, P.Eng.
Board Member

B. F. Bietz, Ph.D.
Board Member

M. J. Bruni
Acting Board Member

R245

ENERGY RESOURCES CONSERVATION BOARD

Calgary, Alberta

GULF CANADA RESOURCES LIMITED
COMPULSORY POOLING
FENN-BIG VALLEY FIELD

Addendum to Decision D 90-9
Application 900374

1 BACKGROUND

On 24 August 1990, the Board issued Decision D 90-9 respecting an application by Gulf Canada Resources Limited (Gulf), made pursuant to section 72 of the Oil and Gas Conservation Act (the Act), for six compulsory pooling orders that would combine all of the tracts within each of six gas drilling spacing units (DSUs) as a unit to permit the production of gas from wells existing in each of the DSUs.

Among other things, the Board in its decision outlined the broad principles to be followed in determining well costs for the purpose of any Board order issued in the matter, and the application of a penalty against those costs.

Since the issuance of that decision, it has come to the Board's attention, through a submission dated 9 October 1990 by one of the parties involved in the hearing, Shaman Energy Corporation (Shaman), and responded to by the applicant, Gulf, in a submission dated 23 November 1990, that confusion exists between Shaman and Gulf as to the Board's intent in the decision report in determining relevant drilling and completion costs for the well, GULF FENN BIG VALLEY 7-27-35-20 (7-27 well), for the purposes of a Board order. There also seems to be some disagreement between the companies as to when the penalty against drilling and completion costs comes into effect.

The Board notes that in accordance with its decision, it is prepared to approve, with the consent of the Lieutenant Governor in Council, the 7-27 well as the producing well for Basal Belly River gas production from the DSU comprising section 27 of township 35, range 20, west of the 4th meridian.

The purpose of this addendum, then, is to clarify how the Board, in its decision, intended the parties to determine applicable drilling and completion costs for the purpose of Belly River gas production through the 7-27 well, and when the penalty provision is applicable.

2 VIEWS OF SHAMAN AND GULF

Shaman states that for determining the drilling and completion costs for the 7-27 well, it interprets the Board's intent in the decision report to be that the well cost is one-half of an average cost of drilling a well to, and completing it in, the Basal Belly River zone, the average cost being determined from five other Basal Belly River wells presented at the same hearing.

Gulf, on the other hand, believes the Board's intent was that only the drilling costs of the five wells be averaged and one-half of that amount be considered, and that the completion costs for the 7-27 well be the total and actual completion costs incurred by Gulf to complete the 7-27 well in the Basal Belly River zone.

In considering the timing of the penalty to be applied to the drilling and completion costs, Shaman believes that, in accordance with the Board's decision, the penalty is not to be applied until 30 days after the latter of all of the following three conditions have been met: the tract owner has been notified of such costs, a pooling order has been issued by the Board, and the subject well begins producing to its market.

Gulf, on the other hand, believes that the Board's decision implies that the penalty is applied 30 days after a tract owner has been given notice of its share of well costs, but providing a pooling order has been issued by the Board upon approval of the Lieutenant Governor in Council, and the subject well begins producing to its market. Thus, Gulf's position is that if the tract owner has been given sufficient notice of well costs, and the well is already producing to its market, then the penalty becomes effective immediately upon issuance of an Order in Council from the Lieutenant Governor in Council.

3 CLARIFICATION BY THE BOARD

In determining well costs for the 7-27 well, the Board recognized that the well represented a special situation; that is, it was drilled for the purpose of evaluating formations below the Basal Belly River. Thus, it was the Board's intent to treat only the cost of drilling the well in a special way. The cost of completing the well was not specifically addressed because it was the Board's intent to have the completion cost for the 7-27 well determined in the manner prescribed in section 75, subsection (1) of the Act, that is, the actual cost incurred by Gulf in completing the 7-27 well in the Basal Belly River sand.

For the drilling cost attributable to the 7-27 well, the Board ruled in its 24 August 1990 decision that the cost was to be determined by discounting the average cost of a Basal Belly River well in the area by one-half, and then Shaman compensating Gulf, on an areal basis, for that discounted cost. The Board believed that the average drilling cost of a Basal Belly River well in the area could be determined with sufficient accuracy by averaging Gulf's actual costs, less any extraordinary expenses (and void of any completion costs), for the other five Belly River wells presented during the hearing.

For the completion cost attributable to the 7-27 well, the Board intended that Shaman would share, on an areal basis, the actual cost incurred in completing the 7-27 well in the Basal Belly River.

Section 72, subsection (5) of the Act gives the Board the authority within the order to specify that a penalty be applied against a tract owner's share of drilling and completion costs, if that tract owner does not pay those costs within a specified time. Accordingly, as to the application of the penalty, the decision report clearly states that the Board believes it appropriate to apply a penalty to a tract owner's share of drilling and completion costs if that tract owner does not pay its share of the costs within 30 days of being notified of such costs and provided a pooling order has been issued by the Board and the subject well begins producing to its market.

To clarify this point, in this case the Board intends that the penalty will apply 30 days after the latter of three events has taken place, those events being, the Board has issued a pooling order, the well is on production, and the tract owners have been notified of their share of drilling and completion costs.

DATED at Calgary, Alberta, on 14 December 1990.

ENERGY RESOURCES CONSERVATION BOARD

E. J. Morin, P.Eng.
Board Member

B. F. Bietz, Ph.D.
Board Member

M. J. Bruni
Acting Board Member

ENERGY RESOURCES CONSERVATION BOARD

Calgary, Alberta

GULF CANADA RESOURCES LIMITED
COMPULSORY POOLING
FENN-BIG VALLEY FIELD

Second Addendum to Decision D 90-9
Application 900374

1 ISSUE

Following the issuance of Decision D 90-9 on 24 August 1990 and the addendum to the decision on 14 December 1990, it has come to the Board's attention through a submission by the applicant, Gulf Canada Resources Limited (Gulf) and an intervener to the hearing, Shaman Energy Corporation (Shaman), that the two parties have a disagreement as to the split of drilling costs between geological formations producing through the same wellbore.

The Board notes that for the subject application, the area of disagreement between Gulf and Shaman appears to exist for the following wells which were issued pooling orders subsequent to the issuance of Decision D 90-9 and its addendum:

POOLING ORDER	WELL	APPROVED PRODUCING FORMATIONS
P 99	GULF FENN BIG VALLEY 11-14-35-20	Basal Belly River sand and other Belly River sands above the Basal Belly River sand
P 101	GULF FENN BIG VALLEY 6-10-36-20	Basal Belly River sand and other Belly River sands above the Basal Belly River sand
P 102	GULF FENN BIG VALLEY 16-15-36-20	Basal Belly River sand and the Edmonton sand
P 103	GULF FENN BIG VALLEY 10-24-36-20	Basal Belly River sand and other Belly River sands above the Basal Belly River sand

The purpose of this second addendum, then, is for the Board to direct to Gulf, the operator named in the pooling orders, a fair and equitable method of allocating drilling costs to horizons producing through the same wellbore, such that it may properly invoice drilling costs to tract owners within their respective drilling spacing units.

The Board does not believe this direction applies to the wells relevant to Orders No. P 100 and P 104, namely, GULF FENN BIG VALLEY 7-27-35-20 (7-27 well) and GULF FENN BIG VALLEY 9-27-36-20 (9-27 well), respectively. The issues surrounding the splitting of drilling costs for the 7-27 well between producing formations were different from those of the other five wells presented at the hearing, and the order authorizing production through the 9-27 well approves production from only one formation.

2 DECISION OF THE BOARD

In making its decision on the allocation of drilling costs, the Board notes that all tract owners specific to each of the drilling spacing units have the right to share in all of the production authorized by Board Orders No. P 99, P 101, P 102, and P 103.

The Board believes that all of the drilling costs, void of completion costs, from surface to the deepest pooled formation (ie. total depth of the wells if they are essentially the same as they are in each of those four cases) are required to be shared among tract owners. If a tract owner does not intend to incur the penalty on the drilling costs, it will have to pay all of those costs within the time specified in the order. However, if a tract owner elects to incur penalty and have its share of drilling costs paid from its share of production, all of the drilling costs, plus penalty, will be paid from production revenue from all producing zones in the wellbore. If initially only the Basal Belly River sand produces, then drilling costs, void of completion costs, will be paid only out of production revenue from the Basal Belly River sand; however, if and when a shallower formation commences production, production revenue from that shallower formation can also be used, if still required, to pay drilling costs, plus penalty, for the well. In short, the Board does not believe that drilling costs, void of completion costs, are specific to any one producing formation, but are applicable to all producing formations within the wellbore.

As for completion costs, the Board believes that those costs are specific to the zone being produced and only become payable once the specific formation commences production. If a tract owner does not wish to incur the penalty on the specific completion cost, it will have to pay the cost within the time specified in the order. However, if a tract owner elects to incur a penalty and have its share of completion cost come out of its share of production revenue, then that cost, plus penalty, can be paid only from production revenue from the specific producing formation.

For the four pooling orders at issue in this addendum, with the deepest pooled formation producing, a tract owner would receive "take-home" production revenue for gas production from the Basal Belly River sand for the specific well only if the following costs were paid:

- all of the drilling costs (plus penalty, if applicable), void of completion costs, from surface to total depth, and

- all of the completion costs (plus penalty, if applicable) for the producing Basal Belly River sand.

In the same way, a tract owner could receive "take-home" production revenue for gas production from a shallower zone only if the following costs were paid:

- all of the drilling costs (plus penalty, if applicable), void of completion costs, from surface to total depth, and

- all of the completion costs (plus penalty, if applicable) for the shallower producing sand.

The Board also notes that the direction in this addendum for the equitable sharing of drilling costs, void of completion costs, comes, in some cases, after the nominal date before which a tract owner must pay its cost to avoid incurring the penalty. In those instances, the Board directs that a tract owner be given a

further time limit in which to pay its drilling cost, void of completion cost, without incurring the penalty. That time limit will expire at close of Gulf's business day, 7 calendar days from the date of issuance of this addendum.

DATED at Calgary, Alberta, on 27 March 1991.

ENERGY RESOURCES CONSERVATION BOARD

E. J. Morin, P.Eng.
Board Member

B. F. Bietz, Ph.D.
Board Member

M. J. Bruni
Acting Board Member

ENERGY RESOURCES CONSERVATION BOARD
Calgary, Alberta

APPLICATIONS FOR REDUCED DRILLING SPACING UNITS
MOBIL OIL CANADA
AND PASSBURG PETROLEUMS LTD. — Decision D 90-10
DRUMHELLER D-2 B POOL — Applications 891878 and 900713

1 APPLICATIONS, HEARING, AND DECISION

In Application No. 891878, Mobil Oil Canada (Mobil) applied for drilling spacing units (DSU) of two legal subdivisions (Lsd), being the east half or west half of the quarter section, with the target areas being the northwest quadrant of the southwest and northeast Lsds of the quarter section in accordance with Board Order No. SU 800, for the production of Nisku oil from the southwest quarter of section 22, township 29, range 20, west of the 4th meridian.

In Application No. 900713, Passburg Petroleums Ltd. (Passburg) applied for DSUs of one Lsd in accordance with section 4.020, subsection (2) of the Oil and Gas Conservation Regulations, for the production of Nisku oil from the northwest quarter of section 15, the northeast quarter of section 16 and the southeast quarter of section 21, all in township 29, range 20, west of the 4th meridian.

A public hearing of the applications was held in Calgary, Alberta, on 18 July 1990, before Board Members N. A. Strom, P.Eng., and E. J. Morin, P.Eng., and Acting Board Member J. R. Nichol, P.Eng. The participants at the hearing are listed in the attached table.

Based upon the evidence, the positions and undertakings of the applicants and their responsibilities under the Oil and Gas Conservation Act, the Board decided to grant both applications and advised the participants of its decision at the conclusion of the hearing. Both approvals would be subject to such conditions as the Board would specify. The following gives the reasons for the Board's decision.

2 INTERVENTIONS

An intervention to Mobil's Application No. 891878 was filed by Passburg expressing the view that spacing for the entire Drumheller D-2 B Pool should be reduced to one Lsd. Greystone

Resources Ltd. also filed a letter of intervention, contending that reduced spacing was not appropriate, but it did not participate in the hearing of the application.

An intervention to Passburg's Application No. 900713 was filed by Mobil for the purposes of cross-examination, adducing evidence, and making argument.

3 BACKGROUND

Upon receipt of Mobil's application and interventions filed thereto, the Board sent a letter to all operators in the Drumheller D-2 B Pool on 8 March 1990, requesting submissions pertaining to spacing and related matters. The Board received submissions from Inverness Petroleum Ltd., Greystone Resources Ltd., Bounty Developments Ltd., Passburg Petroleums Ltd., Mobil Oil Canada, Amoco Canada Petroleum Company Ltd., ATCOR Ltd., and Samedan Oil of Canada, Inc.

Of the above companies, three attended but declined to participate in the hearing and three did not attend. This left the applicants, Mobil and Passburg, as the only active participants.

4 VIEWS OF THE APPLICANTS

Mobil and Passburg generally presented similar views regarding reservoir characteristics, ie, favourable fluid and rock quality, very high permeability, strong bottom-water drive, and geological complexities where local "attic" areas could exist because of an irregular crestal surface of the Nisku Formation.

Mobil and Passburg both stressed that to maximize oil recovery, additional wells would have to be located in technically identified structural highs. Passburg stated that it believed one Lsd spacing would provide the flexibility needed to recover "attic oil". Referring further to the advantages of flexible locations, Mobil stated that its 4-22-29-20 W4M well, though perforated lower than surrounding wells, will likely recover additional oil from the pool by continuing to produce when those wells have watered out.

With regard to equity concerns, Mobil stated that a 100-m set-back from lease boundaries and a minimum 100-m interwell distance should be satisfactory.

Passburg suggested that a minimum interwell distance of 200 m would be more appropriate.

Mobil and Passburg were each receptive to their counterpart's application being granted.

No other party raised an equity concern at the hearing.

5 REASONS FOR DECISION

The Board accepts that reduced well spacing which allows flexibility in the location of wells would result in improved oil recovery from this pool. The Board recognizes that the adoption of a uniform spacing within a pool would normally be desired to address equity and drainage concerns. However, in this case it is satisfied that equity concerns can be accommodated by appropriate set-back and interwell distance provisions.

6 DECISION

The Board approved Application No. 891878 and Application No. 900713 at the conclusion of the hearing. Accordingly, the appropriate amendments to Board Order No. SU 1643 will be issued reflecting this decision.

DATED at Calgary, Alberta, on 20 September 1990.

ENERGY RESOURCES CONSERVATION BOARD

N. A. Strom, P.Eng.
Vice Chairman

E. J. Morin, P.Eng.
Board Member

J. R. Nichol, P.Eng.
Acting Board Member

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Mobil Oil Canada (Mobil) A. L. McLarty	D. Monroe, P.Eng. H. Lavallee
Passburg Petroleums Ltd. (Passburg) J. K. Ferris	D. Fuchs, P.Eng. J. Look, P.Geol.
Energy Resources Conservation Board staff D. H. Lehmann, P.Eng. C. Lochhead	

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

DEPARTMENT OF ENERGY, GOVERNMENT OF ALBERTA
RESCISSION OF SPECIAL GAS DRILLING SPACING UNITS
PEMBINA AND WESTEROSE AREAS

Decision D 90-11
Application 891965

1 INTRODUCTION

1.1 Application and Hearing

The Department of Energy, Government of Alberta (DOE) applied for an order

- rescinding nine existing special drilling spacing units (DSUs), each comprised of two sections, and
- establishing DSUs of one section in accordance with Board Order SU 1088,

for the production of gas from the Banff Formation in sections 6, 7, 18, and 19 of township 46, range 1, west of the 5th meridian (46-1 W5M); sections 1 to 4 inclusive, 9 to 13 inclusive, 15, 16, 21, 22, and 24-46-2 W5M. For ease of reference in this report, the special DSUs are referred to as, for example, DSU 6/7, describing the DSU comprised of sections 6 and 7-46-1 W5M.

The attached figure shows the special DSUs involved, together with the lessors and lessee/working interest holders in and adjacent to the area of application.

The application was considered at a public hearing held in Calgary, Alberta, on 24 and 25 July 1990, before Board Members G. J. DeSorcy, P.Eng. and J. P. Prince, Ph.D., and Acting Board Member J. D. Dilay, P.Eng.

The attached table lists those who appeared at the hearing and abbreviations used in this report.

Petro-Canada Inc. (PCI) and Altex Resources Ltd. (Altex) filed submissions in support of the application; PanCanadian Petroleum Limited (PCP) and Poco Petroleums Ltd. (Poco) submitted interventions opposing the application. The Midtdals filed an intervention which neither supported nor opposed the application and did not appear at the hearing.

1.2 Basis for Establishment of Special DSUs

The Board believes the fundamental reason for the establishment of special DSUs is to provide flexibility in well spacing and target areas, thereby allowing for efficient and economic development of resources under variable topographical, geological, or reservoir conditions.

In the Board's view, the considerations relevant to establishing special DSUs are generally as follows:

- Resource conservation, that is, whether the proposed special spacing would affect the recovery of the resource.
- Economics and efficiency, that is, whether altered facilities could effectively recover the resources, such that the economics of the special spacing were more favourable than the economics of standard spacing.
- Equity, that is, whether the special spacing would have any unacceptable effects on another party's opportunity to recover its share of the resource.
- Land use, that is, whether the proposed special spacing would have significant effects on land surface use.
- Land tenure policy, that is, whether the proposed special spacing would be contrary to the intent of the legislation governing land tenure.

A relatively common reason for requesting a larger-than-normal DSU is to obtain off-target penalty relief. In such situations, the above issues would be considered, and economic efficiency, resource conservation, and equity would be critical factors. Although frequently used to deal with off-target wells, special spacing is not intended as a tool to prevent normal competitive operations. Also, where there is insufficient data to establish the geological and productive characteristics of a pool, the Board would normally maintain the standard size of spacing unit for the area.

1.3 Basis for Rescinding Special Spacing Units

The Board believes that established spacing rules, which all parties are aware of and expect to operate under, should not be changed without sound reasons. This applies to special spacing units that have been in place for some time as well as to normal spacing. Notwithstanding the above, the Board would be prepared to approve applications for the rescission of special DSUs which are not contested for equity reasons, if they are generally acceptable with respect to resource conservation and the other relevant issues. Where an application to rescind special DSUs is contested, as in the subject case, the decision will hinge on whether the objections justify the maintenance of the special DSU. This will depend on how conservation, efficiency, equity, land use, and land tenure policy are affected in each individual case.

1.4 Background

The subject special DSUs were established in 1974 for the development of gas in the Banff Formation as a result of Application 8098, by Texaco Canada Limited on behalf of itself, Canada-Cities Service Ltd., PCP, Pacific Petroleums Ltd., Siebens Gas & Oil Ltd., and Supertest Investments Ltd. (Texaco et al). The applicants submitted that development on two-section DSUs would be more economically attractive than on the basis of one-section DSUs. Texaco et al interpreted a pool of fifteen sections in

area and expected that development on two-section DSUs would provide sufficient productivity to drain the pool in 10 years. The applicants also argued that the proposed spacing would minimize potential lease line problems related to the different lessors in the area. All of the special DSUs have mixed Crown and Freehold mineral ownership, except DSU 2/11, where the Crown is the only mineral owner.

The Board published notice of the 1974 application and received no objections. The Board subsequently granted the application and issued Order SU 824 establishing ten special DSUs. DOE has not requested the rescission of the DSU comprised of sections 14 and 23-46-1 W5M.

At the time Application 8098 was submitted, the only Banff well in the area was the Texaco Canada Limited well located in legal subdivision (Lsd) 3-23-46-2 W5M (the 3-23 well), which had been drilled in 1969 off target for the one-section spacing in effect at the time. The 3-23 well began producing from the Pembina Banff D Pool in 1978 and has continued to produce to date. Following approval of Application 8098, a number of wells were drilled into the Banff Formation, as shown on the attached figure. Of these wells, only those drilled by PCI in Lsd 6-6-46-1 W5M (the 6-6 well) and Lsd 8-12-46-2 W5M (the 8-12 well) encountered productive Banff reservoirs.

PCI drilled the 6-6 well in 1985 and produced it for 13 months (11 months in 1989) from the Westerose Banff A Pool without the required agreement for the pooling of mineral rights within the two-section DSU involved (DSU 6/7). In the later part of 1989, after PCI was informed of the existence of the two-section DSU, the well was first shut in and then produced with the concurrence of affected parties with the proceeds flowing into an escrow account pending resolution of pooling and spacing matters. The well has been shut in since January 1990.

The 8-12 well was drilled in December 1989 and at the time of the hearing had not yet been completed or tied in to any gathering system.

2 ISSUES

The Board considers the issue to be whether the rescission of the special DSUs involved would have an unacceptable net impact on the criteria set out above: resource conservation, efficiency, equity, land use, and land tenure policy.

3 VIEWS OF DOE

DOE argued that the special DSUs in question should be rescinded for three reasons.

Firstly, the continued existence of the enlarged spacing compromises the intent of current land tenure legislation by obliging the Crown to continue mineral rights where it is not warranted. Under existing legislation, lessees retain only those mineral rights which are demonstrated productive. Continuation is based on the DSU. In a case where one section in a two-section DSU is proven productive in a

specific zone, while the other section is proven to be unproductive in the same zone, land tenure legislation would oblige DOE to continue the mineral rights within the entire DSU, including the unproductive section. This would be contrary to the intent of the legislation and could result in the sterilization of up-hole mineral rights for potential lessees who would otherwise have had access to them.

Secondly, the special DSUs have not fulfilled their intended purpose, and there is no justification for their continued existence. The DSUs were established in order to develop reserves in a fifteen-section area; however, the anticipated potential has not been realized through further drilling. DOE did not present any geological, reservoir, or economic evidence, but noted that there were unsuccessful Banff wells drilled in DSUs 3/10, 4/9, 13/24, and 16/21. In DOE's view, there is no evidence of Banff reserves in the two undrilled DSUs 18/19 and 15/22, and it would be sheer speculation to suggest that it would be appropriate to drain any gas which may underlie the two sections with only one well. Additionally, there is no evidence of reserves underlying DSU 2/11. In DSU 1/12, it appears that there may be reserves underlying only one of the sections. This would leave only DSU 6/7, which DOE argued should be rescinded for the reason given below.

Thirdly, the special DSUs involved are not justified because they are not in accordance with current practices. The applicant stated that target areas for standard one-section spacing maintain an acceptable drainage area within the reservoir for each producing well, while allowing for competitive, yet fair and equitable, production between operators in their own spacing units. DOE's position was that enlarged DSUs are appropriate to avoid unfair drainage by a well that would otherwise be off target and where there was evidence showing that the well would drain the gas underlying the DSU in a reasonable period of time and in an efficient and economic manner. PCI's 6-6 and 8-12 wells are the only wells in the area of application which are productive from the Banff Formation. Both of these wells would be on target for standard one-section DSUs; therefore, correlative rights are not in jeopardy if the application is approved. Further, DOE noted that the special DSUs were established with the target areas being in the central portion of either section in accordance with the standard one-section spacing provisions in 1974. In DOE's view, the present normal practice would be to establish an enlarged DSU with a centrally located target area to accommodate a well which would otherwise be off target.

DOE also noted that some of the lessees of Crown mineral rights, and possibly of Freehold interests, have changed in the area of application since the time Application 8098 was approved. The continued existence of the special DSUs penalizes lessees who were not party to the original application and who have subsequently determined that standard one-section spacing and target areas are appropriate for the development of Banff gas reserves in the area.

With respect to other equity issues, DOE stated that, regardless of the outcome of the hearing, an accounting would have to take place regarding the disposition of production from the 6-6 well which occurred in the absence of a pooling agreement among the mineral interest holders in DSU 6/7. However, the applicant declined to comment on whether, if the application is approved, PCI's 6-6 well should be shut in for some specified time period to allow the lessees of mineral rights underlying section 7-46-1 W5M the opportunity to drill and produce their own well competitively with the PCI well. DOE stated that as a steward of a resource, it is generally concerned about inequitable

drainage; however in this case, the decision as to whether the rescission of the special DSUs would be fair to the parties involved would be within the Board's jurisdiction, not DOE's.

When questioned respecting the possible impact of approval of the application on surface land use, DOE stated that such impacts would not be different than what exists in most of the province where gas reserves have been developed on the basis of one-section DSUs.

4 VIEWS OF PCI

PCI submitted that normal one-section spacing should be used unless there are compelling reasons to support special or extraordinary spacing. It contended that there are no such reasons justifying maintenance of the subject two-section DSUs; the data available indicate that the most appropriate method to produce Banff gas reserves in the area would be on normal one-section spacing.

PCI interpreted the Banff Formation in the general area of application as a tight limestone facies with the exception of some structurally high dolomitized remnants, which can exhibit excellent porosity and contain significant hydrocarbon reserves. However, the pools are generally limited in areal extent from less than one to three or four sections. PCI mapped the Banff pools encountered by the 6-6 and 8-12 wells as separate, single-well pools, with the pool penetrated by the 6-6 well extending over most of section 6-46-1 W5M and portions of sections 5 and 7-46-1 W5M, and the pool encountered by the 8-12 well extending over most of section 12-46-2 W5M, small portions of sections 7 and 19-46-1 W5M, and sections 1 and 13-46-2 W5M. The assumption of separation between the two pools is based on different gas/water contacts in the 6-6 and 8-12 wells. PCI acknowledged that there was a transition zone in the 8-12 well which made the determination of a gas/water interface interpretive; however, it had sufficient confidence in its analysis to map the wells into separate pools. The interpretation of separate pools is also supported by seismic data, but PCI did not present such data because of their interpretive nature. PCI did not consider the pressure data obtained at the 8-12 well as conclusive evidence that the 6-6 and 8-12 wells are in the same pool. The pressure of the Banff Formation at the 8-12 well in December 1989 was 15 100 kilopascals, which was lower than the initial pressure, and similar to the current pressure, of the zone at the 6-6 well. However, PCI argued that the lower pressure at the 8-12 well could also indicate that the two wells are in separate pools. PCI also speculated on the possibility of a separate structural high underlying section 7-46-1 W5M that is not connected to the one associated with the 6-6 well, but it did not map the structure because it did not have any geological data, only seismic data, to support the interpretation. PCI argued that single-section DSUs for these types of discontinuous, limited reservoirs could result in greater recovery, because in a larger DSU some reserves may be isolated from the producing well and may never be recovered.

PCI argued that its studies demonstrate that the reservoir characteristics, including permeability, of the Banff Formation in the area of application are not unusual in any way, and do not justify two-section DSUs. It contended that the 3-23 well, which is similar to the 6-6 well, has produced from the Banff Formation for some 7 years, and has recovered 84 per cent of the marketable gas reserves underlying the section, but only 42 per cent of the gas underlying the two-section DSU involved. In PCI's

opinion, it would take another 20 years to drain the reserves underlying the two-section DSU; however, there are good indications that the well could water out before it can produce all of the reserves. PCI said that other Banff reservoirs in the area could produce water; therefore, it would seem that one-section spacing would be more appropriate for development of the formation. Specifically in regard to the reservoir encountered by the 6-6 well, PCI's view was that it would take an unacceptably long time to drain the reserves underlying both sections 6 and 7-46-1 W5M, if the well could drain the reserves at all, given the possibilities of water problems or a separate structure in section 7-46-1 W5M. The intervener stated that its material balance analysis shows the well would drain something less than one section.

PCI argued that its economic analysis demonstrates that one well on each section would be more economically attractive than one well draining a two-section DSU. It presented an analysis based on a theoretical case where PCI was the common leaseholder in two sections with the choice of drilling one well or two. It assumed two wells would not result in incremental recovery and production would not be limited by market or transportation restrictions. No attempt was made to account for possible water influx or discontinuous reservoirs. PCI stated that the analysis shows that one well per section would result in a reduced length of time for project payout, a higher rate of return, a more reasonable project life, and a net incremental benefit of $700 000 over the one well per two-section DSU case. The economic benefits would be enhanced for the one well per section case if water coning or the possibility of a separate structure in section 7-46-1 W5M were taken into account, or if the analysis were based on the interpreted pool outline. PCI acknowledged that the production profile used was not typical, but argued that if a more realistic projection were used to account for market or transportation limitations, the economics of one well per section would still be more attractive than one well per two-section DSU. PCI also acknowledged that transportation limitations would affect the type of gas purchase contract to which the gas could be supplied and consequently the value of the gas.

PCI said that it would take a considerable period of time to drill and produce a well in section 7-46-1 W5M. However, it was opposed to a suggestion that, if the application were approved, the 6-6 and 8-12 wells be shut in to allow the lessees in section 7-46-1 W5M a fair opportunity to compete for the resources. PCI would lose any return on its investment during a shut-in period; this would penalize PCI which risked the capital to develop reserves in the area, but would benefit others who could capitalize upon the discovery made by PCI through reduction of risk that they now incur in relation to drilling a well in section 7-46-1 W5M. In the intervener's view, approval of the application would place off-setting mineral holders in a better position than they would have been in normal circumstances throughout the province. That is, in normal circumstances, the offsetting party, having become aware of the presence of a competing well, would then have to take the time and effort to develop its own resource. In the present situation, the lessees of Banff gas underlying section 7-46-1 W5M have been aware for several months of the possibility of a change in spacing in the area. The parties now have extensive analyses to assist them in siting a well. They would have to resolve external problems in the same way that other parties such as PCI have had to resolve their problems in the area. PCI noted that both the 6-6 and 8-12 wells are on target for standard one-section spacing, and expressed the opinion that any drainage occurring would be limited to the time it would take to complete the development. In PCI's view, approval of the application would impose only a small burden on the mineral holders offsetting section 6-46-1 W5M.

With respect to environmental issues, PCI stated that approval of the application would not result in any significant proliferation of wells. It said that drilling on standard one-section DSUs is deemed adequate throughout the province, and would not be considered as resulting in a proliferation of wells. The intervener pointed out that only Banff gas wells are affected by the special spacing in the area, such that the maintenance of the special DSUs would not prevent other wells from being drilled in the area on the basis of the one-section spacing that exists for other zones. Further, approval of the application would result in the drilling of one additional Banff gas well in section 7-46-1 W5M; in PCI's view this would not be proliferation that would cause concern.

PCI submitted that, in the absence of a clear agreement between landholders concerning how to share production, two-section DSUs are likely to increase lease and land tenure problems rather than minimize these concerns as originally proposed by Texaco et al in 1974.

PCI concluded that there are no compelling reasons to maintain the special DSUs in the subject area, and submitted that the spacing should, therefore, be returned to normal, single-section spacing.

5 VIEWS OF ALTEX

Altex submitted that single-section gas spacing for deeper zones is a well-established principle in the province. It stated that a larger-than-normal DSU would be appropriate in exceptional circumstances where there is an off-target well which would otherwise be penalized, or where for a specific well the parties involved have a logical reason for requesting a special DSU and the economics supported the request. However, in Altex's opinion, one-section DSUs for Banff gas in the area of application would be appropriate.

Altex did not present any technical analyses, but said that its interpretation of the geology and reserves in the area was not dissimilar to PCI's. It also noted that its recently drilled well in Lsd 16-1-46-2 W5M, which was not productive in the Banff Formation and has been abandoned, shows that drilling is required to verify the seismic and geological data used to locate a well.

The intervener indicated that Banff gas in the area has a high liquid hydrocarbon content, and therefore, one well per section would recover more of the heavier hydrocarbons. Altex also suggested that the special DSUs affected conservation because the difficulties of pooling interests within the special DSUs inhibit development of Banff reserves. The intervener's opinion was that conservation of Banff gas would best be handled either competitively or through unitization.

Altex stated that it had completed its own economic analysis for a one-well per section case in the area and found it to be an acceptable risk. The intervener also examined PCI's comparison of the economics of a one-section DSU versus a two-section DSU and found the parameters used and the conclusions to be factual and realistic. From the standpoint of a Freehold mineral owner who cannot afford to take a long-term view in the same manner as a company or government, the economic analyses indicate that one well would take an unacceptably long period of time to drain the reserves underlying two sections.

Altex submitted that pooling interests and allocating production are difficult matters even for one-section spacing. If all of the special DSUs were productive, the DSUs would result in fair and equitable operations. However, not all of the special DSUs are productive, and in some cases only portions of a DSU are. The existing special DSUs tie the Crown and Freehold sections together to the potential detriment of either the Crown or the fee simple owner, depending on which section a productive well is drilled. The intervener was also concerned that the parties who hold interests in the area today are not necessarily the same parties who made the commitment in 1974 that pooling in the special DSUs would be done on an acreage basis. Altex was of the view that any attempt to pool on a reserves basis could likely be effected only through a compulsory pooling application submitted to the Board.

Altex did not make any comments on whether, if the application is approved, the 6-6 and 8-12 wells should be shut in for some period of time to allow the lessees of Banff gas underlying section 7-46-1 W5M an opportunity to drill and produce their own well. It said that 6 or 7 months of lead time to complete an analysis respecting where to locate a well would substantially shorten the time needed to drill a well. However, Altex acknowledged that it would take a considerable period of time to arrange for transportation and processing of gas discovered in the area.

Altex concluded that one-section DSUs for Banff gas in the area are not unreasonable, and it supported the application to rescind the special DSUs of interest.

6 VIEWS OF PCP

PCP submitted at the hearing that it did not oppose the rescission of those special DSUs which have not been drilled or which have been drilled but have no productive Banff gas well. The intervener has no interest in DSU 1/12 and did not wish to take a position on the rescission of it. PCP's concerns related to DSU 6/7, containing PCI's productive 6-6 Banff well.

PCP was of the view that two-section DSUs would be appropriate where one well would be capable of draining the reserves underlying the two sections in a reasonable period of time, and where equity concerns have been satisfied. The intervener noted that no evidence was offered in support of the proposition that there should be no enlarged DSUs without an off-target well, and it expressed the view that a central location for a well in a two-section DSU would not be essential if the well had penetrated the best part of the reservoir. PCP argued that the evidence supported the maintenance of DSU 6/7.

PCP submitted a structure map based on seismic data which was not presented at the hearing, and on available well control. The map shows the PCI 6-6 and 8-12 wells in a single pool underlying most of sections 6 and 7-46-1 W5M and section 12-46-2 W5M. The intervener did not see any evidence to suggest a Banff reservoir underlying section 7-46-1 W5M would not be in communication with that underlying section 6-46-1 W5M, but its seismic data showed an anomalous feature between the 6-6 and 8-12 wells. However, geophysical modelling confirmed PCP's opinion that the feature is more likely a variation in porosity, which would not prevent communication between the two wells, rather

than a structural low separating the two wells into different pools. PCP also supported the mapping with its interpretation of a common gas/water interface in the 6-6 and 8-12 wells, but it acknowledged that determining the gas/water interface in the 8-12 well was difficult because the reservoir quality at the well is poorer than at the 6-6 well. The intervener also considered the lower initial pressure of the Banff Formation at the 8-12 well as additional support for including the 6-6 and 8-12 wells in the same pool. In PCP's view, the Banff reserves contained in small structural highs in sections 6 and 7-46-1 W5M would not be more likely to be stranded and not recovered under a two-section DSU than under one-section DSUs.

PCP argued that both the 3-23 and 6-6 wells, which are similar, would be capable of draining a two-section DSU in a reasonable period of time. Using material balance analyses and wellbore reservoir parameters, it calculated a drainage area of two sections for the 3-23 well, and 1.9 sections for the 6-6 well. Its analyses further showed that the 3-23 well has drained 52 per cent of the reserves associated with its two-section DSU over a 5.6-year period of continuous operations, and would drain the remaining reserves involved in about 18 years. PCP's calculations using PCI's theoretical production forecasts for DSU 6/7 showed that, in a 24-year period, one well would drain about 86 per cent of the recoverable reserves assigned, while two wells would drain about 93 per cent of the reserves. PCP acknowledged, however, that under the PCI forecast, it would take longer, possibly more than 30 years, for one well to recover the same volume of reserves as two wells. The intervener did not consider potential water problems in the 6-6 well to pose a significant problem to recovery because the well has already produced some 29 million cubic metres of gas and only 17 cubic metres of water.

PCP did not present any economic analyses but acknowledged that the PCI analysis shows a higher net present value for the case where two wells are draining two sections than where one well is draining two sections. However, it did not see a marked difference in the rate of return between the two cases. The intervener further noted that the cases presented by PCI assumed two identical wells producing at identical rates, and did not account for possible market restrictions.

PCP submitted that development on two-section DSUs would prevent unnecessary capital expenditure for drilling additional wells and constructing the associated facilities. The intervener was of the view that there was some capacity available on a best-efforts basis on the existing pipeline to the plant where the gas would be processed. It was also of the opinion that production from the 6-6 and 8-12 wells and a well in section 7-46-1 W5M would not be able to bear the cost of twinning the existing pipeline to the gas plant.

PCP has not quantified the economic benefits of pooling in DSU 6/7 versus drilling a well in section 7-46-1 W5M, but was of the opinion that it would be economically preferable to pool the existing two-section DSU.

PCP submitted that if DSU 6/7 were rescinded, the 6-6 well could be placed on production immediately. However, PCP is not in a position to develop section 7-46-1 W5M on a competitive basis because it does not have all of the Banff gas under lease in the section and could not license a gas well to be drilled in the section until this has been accomplished. The intervener argued that if the application were approved, it would be unable to protect its reserves underlying section 7-46-1 W5M except by requesting that the 6-6 well be shut in for some period of time to allow the lessees in section 7-46-1 W5M the opportunity to drill their own well.

PCP submitted that development on two-section spacing would minimize the environmental impact and topographical problems associated with the construction of leases, facilities, and pipelines.

PCP argued that DOE's current land tenure policy is not sufficient reason to rescind any special DSUs containing productive wells.

In summary, PCP concluded that there is no reason to rescind DSU 6/7 and it opposed the application in this respect.

7 VIEWS OF POCO

Poco has an interest in section 7-46-1 W5M and its submission related only to DSU 6/7.

Poco's view was that enlarged DSUs would be appropriate where all parties agreed it would be of economic benefit to have such a DSU. The intervener said that the Board should consider conservation issues if appropriate, but that the presence of a well which would be off target on standard spacing should not be a prerequisite to the establishment of an enlarged DSU. Poco argued that the Board should only rescind special DSUs on the basis of clear and uncontradicted evidence that the original reasons for establishing the DSUs are no longer valid and that maintaining the DSUs would be contrary to the orderly, efficient, and economic development of the resource. The Board should not rescind any DSU where the evidence is contested and where the parties who have relied on the special DSU to protect their interests would be prejudiced by the rescission of the DSU. In the case of DSU 6/7, the evidence supports the maintenance and not the rescission of the DSU.

Poco argued that the onus was very high on anyone wanting to rescind a special DSU to present justification in support of that position. It contended that very little weight should be given to DOE's application because it did not contain any technical support for a matter which requires a high degree of technical justification, but is based on policy considerations which should not be important factors in rescinding a special DSU.

Poco did not submit any geological evidence but stated that its review of log, test, and pressure data, together with limited seismic data, indicated the presence of a structural high over portions of sections 5, 6, and 7-46-1 W5M and sections 1 and 12-46-2 W5M. It saw a change in the seismic signature on a line between the 6-6 and 8-12 wells, but did not draw any conclusions regarding separation of the wells into two pools because the change was open to interpretation. Additionally, it did not place much validity on the pressure taken at the 8-12 well because the test was a partial misrun. While acknowledging that determining gas/water interfaces in the area is highly interpretive, Poco recognized a gas/water interface in the 8-12 well, but did not see a distinct interface in the 6-6 well. Poco specifically concluded from its geological interpretation that there is Banff gas underlying sections 6 and 7-46-1 W5M and that it is probably contained in one pool.

Poco submitted that the 6-6 well should be adequate to drain the Banff reserves associated with sections 6 and 7-46-1 W5M. It was of the view that an additional well in the DSU would not result in any significant increase in recovery because the good porosity and permeability of the pool should provide a drainage area for the 6-6 well in excess of one section. Using material balance calculations and wellbore reservoir parameters, Poco estimated the drainage area for the 6-6 well to be

320 hectares, and it concluded that the 6-6 well would drain reserves underlying section 7-46-1 W5M. Poco did not consider water coning in the 6-6 well to be a threat to recovery because the water zone in the well is very thin, and the well has produced little water to date. If water coning occurred, the problem could be handled under the existing special DSU by shutting in the 6-6 well and drilling another well. Poco argued that there was no evidence to support water coning in the 6-6 well as being a problem requiring the rescission of the DSU involved.

Poco considered PCI's economic analyses to be of little value because they are hypothetical and not site-specific. The intervener submitted its own economic analyses which showed that there would be some economic benefit from producing under a one-section DSU, provided that best-efforts production does not result in any shut-in periods. The analyses are optimistic, however, because the benefit of one-section DSU operation is due to production rate acceleration which may be difficult to achieve. Poco considered limited pipeline capacity to be the most significant obstruction to economic development in the area. It said that the best-efforts capacity available in the existing pipeline to the plant where the gas involved would be processed could result in reduced production which then would result in selling the gas at lower prices. If the analyses included reduced production and lower prices, the economics for the development on the existing two-section DSU would be more attractive than drilling an additional well in section 7-46-1 W5M. If pipeline capacity were shared between the 6-6 well and a well in section 7-46-1 W5M, two wells could be producing at the rate of one well with double the capital investment. Poco noted that it does not have any lands, other than section 7-46-1 W5M, to develop in the area, and it argued that drilling one additional well in section 7-46-1 W5M would not justify constructing additional pipeline capacity to the gas plant. In Poco's view, even the gas from the 6-6 and 8-12 wells and a well in section 7-46-1 W5M would not justify further pipeline construction. Poco concluded that rescinding the DSU involved would be contrary to its economic analysis and would not represent orderly and efficient development.

Poco noted that its equity interests in section 7-46-1 W5M are protected under DSU 6/7. However, if the application is approved, production from the 6-6 and potentially the 8-12 wells would result in significant drainage of reserves underlying section 7-46-1 W5M until a competitive offset location could be drilled. Poco also noted that its Freehold mineral lease would also require it to drill a well in section 7-46-1 W5M if the DSU involved is rescinded. It said that while the two-section DSU exists, its obligation to the Freehold mineral owners is met; however, rescinding the DSU would cause a problem in this regard which should be accounted for. Poco requested that, if the application is approved, the 6-6 and 8-12 wells be shut in for a 3-year period to allow the lessees of Banff gas underlying section 7-46-1 W5M the opportunity to drill and tie in a well. The intervener noted that it had taken PCI some 3 years to put the 6-6 well on production, and it argued that it would therefore seem that 3 years would be an appropriate period of time for the 6-6 and 8-12 wells to remain shut in. Poco dismissed a suggestion that it and PCP should have taken some action regarding a well in section 7-46-1 W5M during the last 7 months or so since it became evident that the special DSU could be rescinded. The intervener said that it was not appropriate to prejudge the application and it would not have been economical to expend funds based on an assumption that might not be valid. As an alternative to shutting in the 6-6 and 8-12 wells, Poco suggested that revenues generated from producing the 6-6 well be shared on an acreage basis among mineral holders in sections 6 and 7-46-1 W5M until the lessees of the gas associated with section 7-46-1 W5M were able to drill and produce their own well.

Poco submitted that rescission of the special DSU would cause increased infringement on the environment by resulting in additional lease preparation, road construction, well-site facilities, pipeline installation, and possibly gas plant expansion.

In summary, Poco supported maintaining DSU 6/7 on the basis of geology, adequate hydrocarbon recovery, economics, equity, and reduced environmental impact. The intervener concluded there was no clear evidence to justify approval of the application and it requested that the application be denied with respect to the DSU of interest.

8 VIEWS OF THE MIDTDALS

The Midtdals did not object to the application or to future development in the area of application; however, they requested that land surface use and air pollution be kept to a minimum, with existing facilities being used and with wells being operated such that no leakage of gas occurred from any facilities on any lease.

9 VIEWS OF THE BOARD

The Board notes there are no objections to the rescission of the seven special DSUs which are either undeveloped or have no productive Banff wells. No specific evidence was presented suggesting that rescission of these DSUs would have any unacceptable impact on resource conservation, economic development, equity, or land use. The arguments presented indicated that rescission of the DSUs would be consistent with current land tenure policy. The Board therefore concludes that there appears to be no reason to maintain the seven DSUs in question.

The Board also notes that the rescission of DSU 1/12 was not directly opposed. The 8-12 well encountered a productive Banff reservoir; however, unsuccessful wells drilled in section 1-46-2 W5M suggest there is little likelihood of significant Banff reserves underlying it. The Board concludes that the distribution of the reserves underlying the two sections would not justify the maintenance of the special DSU.

Most of the argument at the hearing related to the proposed rescission of DSU 6/7, which was opposed by both PCP and Poco.

From the evidence presented at the hearing, the Board concludes that there are probably significant gas reserves underlying section 7-46-1 W5M which are likely in communication with the Banff pool encountered by the 6-6 well. Although there was some speculation that the reserves underlying each of sections 6 and 7-46-1 W5M could be in two separate pools, no conclusive evidence was presented in support of this viewpoint. The Board interprets the Banff pool encountered by the 8-12 well as separate from that encountered by the 6-6 well; however, the nature of the data renders any interpretation to be uncertain.

The Board notes the comparisons drawn between the 3-23 and 6-6 wells in the context of forecasting whether or not the 6-6 well would be capable of recovering the reserves underlying both sections 6 and 7-46-1 W5M. In the Board's view, the evidence suggests that the well might effectively drain the pool; however, even in highly productive formations where the geology is known and no bottom water exists, the recovery of reserves from one well can only be, at best, the same as that from two wells. In the case of the 6-6 well, there was no conclusive evidence that the well would have water problems, but the Board notes some possibility that such problems could occur. The Board concludes that there would likely be an advantage in recovery of gas on one-section DSUs.

The Board's review of the economics associated with a one- or two-section DSU indicates that the analyses are sensitive to the reserves estimate used. A variety of values for original gas in place ranging from PCI's estimate of 447 million cubic metres to less than half of that estimate were considered in the economic evaluation. At the lowest reserves value used, the economics of one well draining two sections were clearly superior to one well per section. However, the Board notes that there was no evidence that the original gas in place would be less than the estimate provided by Poco of 365 million cubic metres. The Board believes that it would therefore be appropriate to use that value as the lower limit in an economic evaluation. Using either Poco's or PCI's reserves estimates, the economics slightly favour the one well per section scenario, except in a case where production from a well in section 7-46-1 W5M is severely restricted, for example, because of pipeline capacity out of the area. The Board notes the arguments at the hearing that there would be transportation limitations that would affect the economics of developing on one-section DSUs, but there was insufficient evidence to determine the extent of the problem. The Board is therefore reluctant to place significant weight on this factor in its evaluation. The Board concludes that the differences in economic efficiency for the two types of spacing, while not great, would favour one well per section.

Given these conclusions regarding conservation and economic efficiency, the Board considers equity to be the most critical factor in the evaluation of the application as it relates to DSU 6/7. Equity within the DSU would continue to be protected as long as the DSU is in effect, since PCI is obligated to share production among the mineral interest holders in both sections in accordance with a pooling agreement. It is clear that a change to one-section spacing would adversely affect the mineral interest holders of section 7-46-1 W5M who are now entitled to participate in the 6-6 well and have had no reason to protect themselves from drainage from the south. It appears to the Board that it would take some time to drill a well in section 7-46-1 W5M and place it on production. During the period that development of section 7-46-1 W5M is proceeding, the 6-6 well could drain a significant volume of the reserves underlying section 7-46-1 W5M.

The adverse effects of changing the spacing would be offset if the 6-6 well remained shut in for some period to allow the mineral interest holders in section 7-46-1 W5M the opportunity to drill a well in the section and place it on production. Alternatively, production from the 6-6 well could continue and be shared under an interim pooling agreement for the two-section DSU for a time period sufficient to allow the mineral interest holders of section 7-46-1 W5M to take some action.

The Board does not consider the 8-12 well as having an unacceptable effect on the mineral interest holders of section 7-46-1 W5M. The configuration of the special DSUs involved is south and north, and the drilling and production of the 8-12 well would be legal and competitively acceptable under the existing spacing in effect for the area.

With respect to land-use issues, the Board is of the view that maintaining DSU 6/7 would result in fewer facilities, which would be particularly desirable in an area where there is recreational activity. However, no specific objections relating to the surface impacts of the development of Banff gas reserves under one-section spacing were raised at the hearing and land-use issues were not dealt with in any significant detail. The Board notes that the rescission of the DSU involved would result in the need for facilities for only one more Banff gas well. However, other wells could continue to be drilled in the general area on the basis of the one-section spacing that exists for other gas zones. The Board concludes that, while there could be some reduced impact on the surface under a two-section DSU, the advantage gained would not be very great.

In the Board's view, the maintenance of DSU 6/7 would not be contrary to land tenure policy because there are likely Banff reserves underlying both sections which could be recovered through the 6-6 well. Therefore, land tenure policy should not be an issue with respect to either the maintenance or rescission of this particular DSU.

The Board notes DOE's argument that DSU 6/7 should be rescinded because the DSU is not in accordance with existing practice, which in DOE's view requires a well which would be off target under standard spacing. In the Board's view, the existence of an off-target well is not a primary factor in justifying either the establishment or the rescission of an enlarged DSU; rather, those issues outlined in Section 1.2 of the report would be the relevant matters to be considered.

In summary, the Board is satisfied that the rescission of the special DSUs subject to the application would not have any unacceptable effects on conservation, efficient and economic development, land use, or land tenure policy. Equity is an issue only with respect to DSU 6/7. The Board is satisfied that equity matters relating to this DSU could be addressed by rescinding the DSU at some time in the future. This would allow the continued production of the 6-6 well under a pooling agreement for the two-section DSU, while providing the mineral interest holders of section 7-46-1 W5M the opportunity to drill a well in the section and prepare it for production. Alternatively, if no pooling agreement were reached, the 6-6 well would be required to remain shut in, and the reserves underlying section 7-46-1 W5M would not be drained while the mineral interest holders of section 7-46-1 W5M were drilling a well in the section and preparing to produce it.

In considering what time would be necessary to drill a well in section 7-46-1 W5M and place it on production, the Board noted some agreement among hearing participants that the development would take appreciable time, with the estimates ranging from less than a year to several years. The Board considers approximately 18 months to be an appropriate period. The Board would, however, be prepared to rescind the DSU sooner if requested by the mineral interest holders of section 7-46-1 W5M.

10 DECISION

Having regard for the conclusions summarized above, the Board grants the application by

- rescinding the DSU comprised of sections 6 and 7-46-1 W5M on the earlier of 15 April 1992 or as soon as administratively possible after receiving a request from the mineral interest holders of section 7-46-1 W5M, and

- rescinding the remaining special DSUs subject to the application in the near future, as soon as administratively possible.

DATED at Calgary, Alberta, on 30 October 1990.

ENERGY RESOURCES CONSERVATION BOARD

G J DeSorcy

G. J. DeSorcy, P.Eng.
Chairman

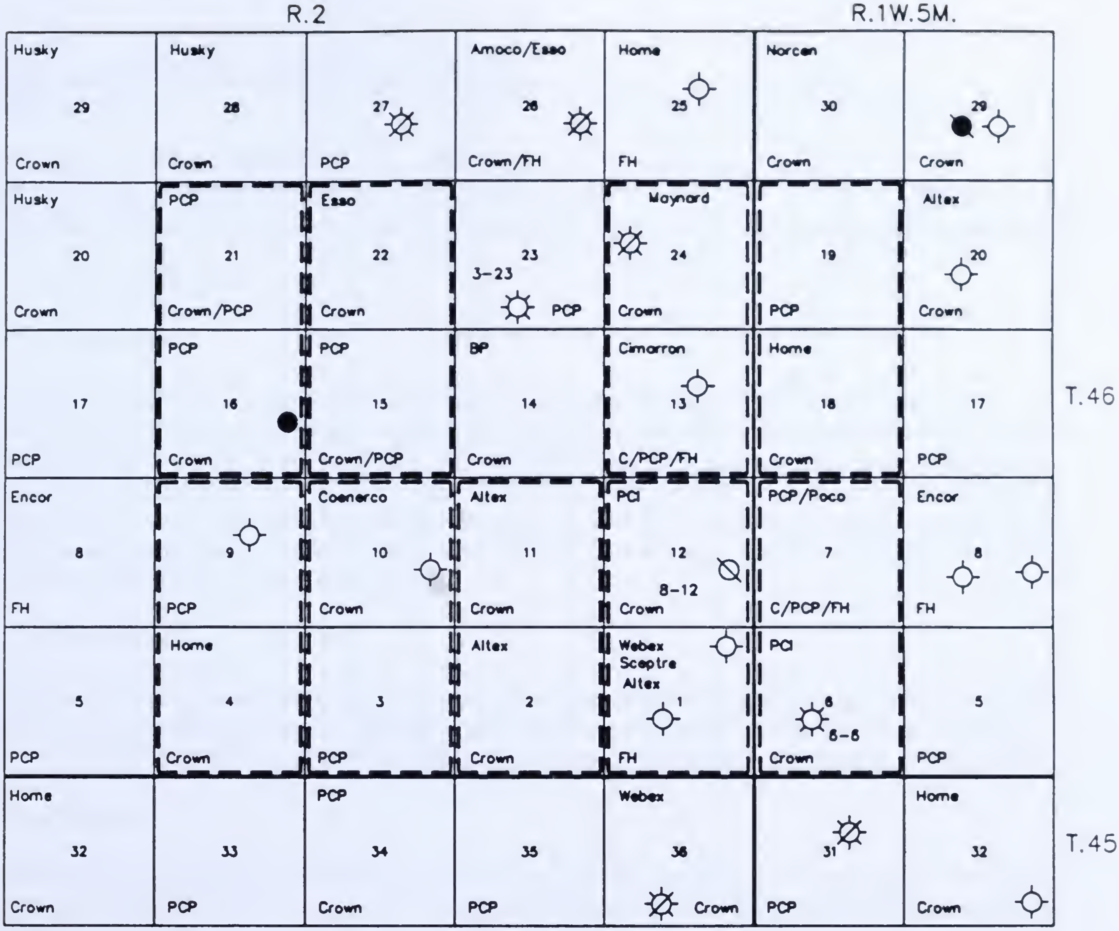
J. P. Prince

J. P. Prince, Ph.D.
Board Member

J. D. Dilay, P.Eng.
Acting Board Member

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Altex Resources Ltd. (Altex) K. Gowertz	
Department of Energy, Government of Alberta (DOE) L. H. Whittaker	D. Luff L. White
PanCanadian Petroleum Limited (PCP) P. R. Murray	J. A. Aitken, P.Geoph. D. G. Bryan, P. Geol. M.J.E. Case C. E. Estabrook, P.Eng. J. H. McMullen
Petro-Canada Inc. (PCI) S. R. Miller	D. W. Fowlow K. A. LaPointe, P.Geol. E. R. Olson, P.Geol.
Poco Petroleums Ltd. (Poco) J. D. Rooke, Q.C.	R. H. Robertson, P.Geol. M. F. Smith, P.Eng.
Energy Resources Conservation Board staff A. Beken, P.Geol. K. Fisher G. Habib M. Pinney	



Capped Gas

Flowing Gas

Pumping Oil

Suspended Oil

Suspended Undesignated

Abandoned

Special Spacing Units Proposed For Rescission

Home — Lessee/Working Interest

Crown — Lessor: Crown (C), PCP, Other Freehold (FH)

Figure shows only those wells which have penetrated the Banff Formation

SPECIAL DRILLING SPACING UNITS
Pembina–Westerose Area
Application 891965

D 90-11

ERCB

ENERGY RESOURCES CONSERVATION BOARD
Calgary, Alberta

BLUE RANGE RESOURCES LTD.
APPLICATION TO AMEND WELL LICENCE NO. 0124875 — Decision D 90-12
SYLVAN LAKE FIELD — Application 900948

1 INTRODUCTION

1.1 Application

Blue Range Resources Ltd. (Blue Range) applied to the Energy Resources Conservation Board (the Board), pursuant to section 20 of the Oil and Gas Conservation Act (the Act), to amend Well Licence No. 0124875 for the well, BLUE RGE ET AL SYLAKE 1-29-38-1, by describing its purpose as being to obtain oil production from the Viking Formation and gas production from the Glauconitic Formation. If granted, this amendment would allow the well to be produced from a one section drilling spacing unit (DSU), specifically section 29-38-1 W5M (section 29) for gas and from a quarter section DSU comprised of the south-east quarter of section 29 for oil.

1.2 Intervention

An intervention to the application was received by the Board from Mission Resources Limited (Mission) opposing the requested amendment. Mission submitted that it held undivided interests in the mineral rights to the Glauconitic Formation (Glauconitic) in two tracts comprising the south half of section 29.

1.3 Hearing

A public hearing of the application was held on 28 August 1990 in Calgary, Alberta, before a division of the Board comprising Board Members G. J. DeSorcy, P.Eng. and B. F. Bietz, Ph.D., and Acting Board Member, M. J. Bruni.

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Blue Range Resources Ltd. (Blue Range) R. A. Neufeld	J. G. Ironside D. A. Orr G. Unrau, P.Geol.
Mission Resources Limited (Mission) H. R. Hansford	R. G. Rhodes, P.Geol.
Energy Resources Conservation Board staff R. D. Heggie N. F. Lord, C.E.T.	

2 ISSUES

The Board considers the issues with respect to the application to be

- the applicant's status as it pertains to section 13 of the Act, and
- the need for pooling, or otherwise to pool all tracts within section 29 in order to form a complete one section DSU prior to placing the well on production.

3 CONSIDERATION OF THE APPLICATION

3.1 Views of Blue Range

Blue Range submitted that with respect to oil production from the Viking Formation, it held an undivided 37.5 per cent interest in the petroleum (oil) rights in the southeast quarter of section 29 and, to its knowledge, the production of oil from the quarter section DSU was not a contended issue.

With respect to gas production Blue Range stated that the rights for the gas-bearing Glauconitic Formation in section 29 were divided into three tracts, these being the north half, southeast quarter, and southwest quarter of section 29. Blue Range claimed that it held an undivided partial interest in the gas rights in each of the three tracts. By virtue of this undivided interest in each of the tracts Blue Range believed it was "entitled... to the right to produce" and also was a "person" or "authorized representative" within the meaning of section 13 of the Act. This compliance to section 13 of the Act gave Blue Range the right to approach the Board for the requested licence amendment under section 20.

Blue Range testified that it had attempted to reach a voluntary pooling agreement but had not been successful. In Blue Range's opinion, its undivided interest in all tracts comprising section 29 gave it the right to produce Glauconitic gas without the necessity of a formal pooling agreement among all interested parties. Blue Range did, however, acknowledge that it had a duty to account to the other interest owners for their appropriate share of production. Moreover, as Blue Range was accountable to all other parties, in Blue Range's view the other interveners would not suffer any adverse impact nor suffer an infringement of their rights.

3.2 Views of Mission

Mission stated that it did not dispute the requested amendment as it applied to the production of oil from the Viking Formation. Mission submitted that with respect to Glauconitic production, Blue Range was not "entitled ... to the right to produce" within the meaning of section 13 of the Act. Section 13, in Mission's view, anticipated agreement among all parties with an interest in mineral rights as they pertain to making well licence applications to the Board. As no agreement was in place among all interested parties, Blue Range did not have the right to produce or to request that the Board amend the existing well licence. Furthermore, Mission believed that Blue Range, since it had separate interests in each of the three tracts in question, was not "a person" (ie. a single entity) or the "authorized representative" of a person who is entitled to produce, and therefore also did not meet the requirements of section 13 in this area as well.

Further with respect to Blue Range's right to produce Glauconitic gas, Mission believed that as the DSU was divided into tracts it would be necessary to pool these tracts to form a complete one section DSU prior to production. This pooling could be achieved through either a voluntary agreement among all parties with an interest or the Board could be approached to consider an application for compulsory pooling. If, however, one of these measures were not employed, Mission believed it would be placed in an inequitable position, and that the well should not be allowed to produce.

3.3 Views of the Board

The Board notes that the production of Viking oil from the DSU comprising the southeast quarter of section 29 is not in dispute and in fact an amendment to the well licence is not required by Blue Range to produce this zone.

With respect to Blue Range's status pursuant to section 13 of the Act, the Board believes Blue Range is a "person" and "authorized representative" within the meaning of the section. By virtue of its undivided interest in the Glauconitic Formation, Blue Range has satisfied the Board that it has the right to act as a "person" and "authorized representative" with respect to making application for the requested amendment.

With respect to the production of Glauconitic gas from section 29, the Board recognizes Blue Range's undivided interest in each of the tracts comprising section 29. The Board believes, therefore, that this undivided interest gives Blue Range the right to production within each of the defined tracts within the DSU. The Board further believes that if the DSU was comprised of only one tract, as was the case in Decision 71-16 which was referred to at the hearing, any of the parties holding interest in the tract would have equal status and rights in approaching the Board for a well licence. Since the DSU would be only one tract, no pooling would be necessary.

In this case, the Board notes that the DSU is made up of three tracts with varying ownership. Therefore, the Board believes that the tracts must be pooled in some manner to form a complete DSU prior to a licence being granted for the production of Glauconitic gas. To this end the applicant has two alternatives, either to pool the tracts on a voluntary basis or to approach the Board for a compulsory pooling order under section 72 of the Act.

4 DECISION

The Board concludes that as separate tracts are clearly defined within section 29, they must be pooled in order to form a complete DSU prior to the production of Glauconitic gas. The application to amend Well Licence No. 0124875 to allow gas production from the Glauconitic is therefore denied.

DATED at Calgary, Alberta, on 1 October 1990.

ENERGY RESOURCES CONSERVATION BOARD

G. J. DeSorcy, P.Eng.
Chairman

B. F. Bietz, Ph.D.
Board Member

M. J. Bruni
Acting Board Member

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

CORVAIR OILS LTD.
APPLICATIONS FOR WELL LICENCES, BATTERY MODIFICATION AND REDUCED OIL WELL SPACING
ARMISIE FIELD

Decision Report D 90-13
Applications 900909, 900910, 900911, 900912, 900913, 900965, 900723

MR. D. BRUCE COOK
CANCELLATION OF WELL LICENCES NO. 63496, 84329, AND 85267

Application 901203

1 INTRODUCTION

1.1 Applications and Interventions

Corvair Oils Ltd. (Corvair) applied, pursuant to section 2.020 of the Oil and Gas Conservation Regulations (the Regulations), for licences to drill wells to be known as CORVAIR ARMISIE 2-33-51-25, CORVAIR ARMISIE 3-33-51-25, CORVAIR ARMISIE 6-33-51-25, CORVAIR ARMISIE 7-33-51-25, and CORVAIR ARMISIE 10-33-51-25 (the proposed wells), to obtain production from the Basal Quartz Formation. The proposed wells would be directionally drilled from a common existing surface lease in legal subdivision 13 of section 33, township 51, range 25, west of the 4th meridian (the proposed surface location). Corvair also applied, pursuant to section 4.030 of the Regulations, for an order establishing 16-hectare drilling spacing units for the production of oil from the Basal Quartz Formation in legal subdivision 10 and the south half of section 33, township 51, range 25, west of the 4th meridian, and, pursuant to section 7.001 of the Regulations, for an approval to modify the existing production facilities located at the proposed surface location.

Interventions opposing the applications were filed by Mr. D. B. Cook, the surface owner of the proposed surface location, Mr. R. d'Alquen on behalf of himself and residents that live near the proposed surface location, and Mr. H. Flewelling, a local resident.

Mr. D. B. Cook also filed an application, pursuant to section 42 of the Energy Resources Conservation Act, for the cancellation of well licence numbers 63496, 84329, and 85267 for wells currently located at the proposed surface location.

1.2 Hearing

A public hearing of the applications was held at the Mayfield Inn in Edmonton, Alberta, on 6 and 7 September 1990, before Board Members F. J. Mink, P.Eng., B. F. Bietz, Ph.D., and Acting Board Member N. G. Berndtsson, P.Eng. (the Board).

At the hearing it was agreed by all parties that the Board would conduct a site visit to the proposed surface location and the general area. The site visit was conducted on 21 September 1990 by the Board and Board staff. The attached figure shows the existing surface locations, proposed well locations, proposed subsurface target areas, residences, and certain features of the area.

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Corvair Oils Ltd. (Corvair) F. M. Saville	R. A. Delbaere, P.Eng. J. K. Farries, P.Eng. of Farries Engineering (1977) Ltd. J. Mitchell K. MacKenzie of MacKenzie Associates Consulting Group Limited
D. B. Cook (Mr. Cook) J. W. Murphy	D. B. Cook W. H. Wolff, P.Eng. of Bissett Resource Consultants Ltd. C. Zeiner of Shaske and Associates
Area Residents	R. d'Alquen
R. d'Alquen	R. d'Alquen
H. Flewelling	H. Flewelling
Energy Resources Conservation Board staff C. S. Richardson C. J. C. Page F. G. Sorenson	

1.3 Background

The proposed wells are located in the Armisie Field, which is defined by Board Order F 833. The Field is comprised of four and three-quarters sections of land. Oil production in the Field is from the Lower Mannville Formation of the Blairmore Group (also referred to as the Basal Quartz Formation) which has been designated the Armisie Blairmore Pool (the Pool). Fluids produced from the Lower Mannville Formation in fields in this area contain small amounts of hydrogen sulphide (H_2S). Oil and gas development has occurred in the Armisie Field area since the early 1950s. Thirty-two wells have been drilled within a 2-kilometre (km) radius of the proposed wells of which 63 per cent were drilled in the 1950s while the rest have been drilled since 1976, 56 per cent have been abandoned, 28 per cent are producing oil wells, and 16 per cent are gas or injection wells. All of the existing wells are located to the north of the proposed wells. The current well spacing for the Field is one gas well per section (section 4.020 of the Oil and Gas Conservation Regulations), one oil well per legal subdivision for the production of oil from the Basal Quartz Formation in the south half of section 4, township 52, range 25, west of the 4th meridian and the north half of section 33, township 51, range 25, west of the 4th meridian, and one well per quarter section for the production of oil from the Blairmore Formation in the north half of section 4 and the southeast quarter of section 5, township 52, range 25, west of the 4th meridian (Board Order SU 1705). The remaining area in the Field is subject to one quarter section spacing with target areas in accordance with Board Order SU 1088 for oil wells.

The surface location for the proposed wells is within the boundaries of the city of Edmonton (the City), and is approximately 150 metres (m) east of 184 Street and 330 m north of the North Saskatchewan River. There are currently three wells located at this site: CORVAIR ARMISIE 11-33-51-25 (the 11-33 well), CORVAIR ARMISIE 12-33-51-25 (the 12-33 well), and CORVAIR ARMISIE 13-33-51-25 (the 13-33 well). The 12-33 well is a suspended gas well drilled in 1980. The 11-33 well (drilled in 1980) and the 13-33 well (drilled in 1977) are producing oil wells. Corvair presently produces the 11-33 and 13-33 wells to production facilities located at the 13-33 site. The facility is effectively two single-well batteries, each consisting of a 2-phase separator and an 80-cubic-metre oil/water emulsion storage tank. The two batteries share a tank vapour gathering system and a 12.5-m flare stack equipped with an automatic igniter. The two wells produce approximately 14 cubic metres per day (m^3/d) oil and 18.5 m^3/d of water. The oil/water emulsion is trucked (approximately two loads per day) to the nearby Denison 6-4-52-25W4 battery (the Denison 6-4 battery) for further processing and disposition. The clean oil is pipelined from the Denison 6-4 battery to market and the water injected into the Lsd 3-4-52-25W4 disposal well. All of the gas (1.4×10^3 m^3/d) from the separator and the tank vapour gathering system is flared through a common flare stack.

The area of application is adjacent to an area defined in ERCB Inquiry Report D 83-F, ERCB Inquiry, Resource Development/Urban Development, West Edmonton Area, (the West Edmonton Inquiry Report) dated 8 July 1983. That inquiry was held for the purpose of reviewing plans for both energy resource and urban development in the West Edmonton area, and to establish guidelines which would allow the developments to co-exist.

Three rural residential subdivisions are located in the area, one approximately 270 m north, a second approximately 400 m southwest, and a third across the North Saskatchewan River approximately 1000 m to the southeast of the proposed surface location. Because of the proximity of the proposed wells to the subdivisions, Corvair provided notification of its plans to drill the wells to landowners and residents in the area. Corvair also held an "open house" on 25 June 1990 to provide information to

residents and landowners in the area of the proposed wells, and to identify any concerns they may have. Subsequent to the open house, correspondence was received by the Board from local residents and landowners expressing opposition to the proposed wells. Concerns were expressed over the potential for odours, H_2S emissions, increased vehicle traffic, and adverse effects on residential quality and property values in the area. Correspondence was also received from the surface owner, Mr. Cook, expressing concern over the productive life of the proposed wells and production facility, and the conflict this caused with his plans to construct a home on the property and for residential development of the property. Mr. Cook also applied to have the licences for the three existing wells at the 13-33 well site cancelled because they were, in his view, originally issued under misrepresentations.

2 ISSUES

The Board considers the issues with respect to the applications to be

- the status of the existing wells,
- the need for reduced spacing and for the proposed wells,
- the surface location of the proposed wells,
- the impact of the proposed wells, and
- the need for and impact of the proposed battery.

3 STATUS OF THE EXISTING WELLS

3.1 Views of the Applicant

Corvair submitted that the estimated remaining life of the existing wells would be 1.5 years for the 13-33 well and 9 years for the 11-33 well. The 12-33 well is currently suspended and Corvair did not have plans to produce it but may convert it to a water disposal well. Corvair stated that the current total monthly fluid production from the 11-33 and 13-33 wells is 1000 cubic metres per month (m^3/mo) and that this rate did not justify the cost of pipelining in order to be able to remove the production equipment from the lease. Corvair intended to continue producing the 11-33 and 13-33 wells at their current maximum rate until the wells reached their economic limit, at which time they would be abandoned. Corvair proposed that all present and future production would continue to be treated at the 13-33 well site.

Corvair stated that it was prepared to work with Mr. Cook to minimize impacts from the existing wells by way of landscaping, fencing, and planting trees and, if the proposed new wells increased the fluid production at the facility to 1600 m^3/mo, by flowlining the production to a remote facility. It submitted that the total capital investment to flowline the production off site would be $254 500.

While Corvair could not comment on the original estimated productive life of the existing wells in the 13-33 well site, it did submit a letter from its files that appeared to demonstrate that Dome notified Mr. Cook in advance of drilling the 11-33 and 12-33 wells.

3.2 Views of the Interveners

Mr. Cook noted that he objected to the drilling of the original well on his property in 1977. He submitted that the ERCB allowed the drilling of the 13-33 well by Westhill Resources Limited (Westhill) at that time on the assumption that the estimated life of the well was 10 years and that this view was reinforced in the ruling by the Surface Rights Board on the compensation for access to the 13-33 well site. He stated that he was not notified by Dome Petroleum Limited (Dome) in 1980 prior to the drilling of either the 11-33 or 12-33 wells from the 13-33 surface location and did not become aware of the wells until after they had been drilled. Mr. Cook noted that he was not advised by Dome until 1988 that the life of these wells would go beyond the estimate made by Westhill for the 13-33 well. Mr. Cook's position was that the three wells had produced for 13 years now, and that the Board, under section 42 of the Energy Resources Conservation Act, should cancel well licence numbers 63496, 84329, and 85267, and require that the wells and facilities be abandoned. This would allow him to proceed with his long-standing plans to build a home near the 13-33 site and pursue residential development of his land. He further stated that as long as the wells were on the property, the impacts from them could not be reduced to the degree that he would find acceptable to build a home. Mr. Cook was of the opinion that Corvair, having purchased the rights to the wells, was also obligated to abandon the surface lease within the time frame predicted by Westhill.

Mr. Cook recognized that the ERCB must consider whether the rights of the surface owner and the mineral owner can both be met without unacceptable impacts being imposed on one or the other. It was Mr. Cook's view that the mineral owner had exercised its rights for a period beyond that which was originally estimated. It was his submission that he should now be accorded his rights to the surface of the land.

Mr. d'Alquen and Mr. Flewelling did not present positions respecting the standing of the existing well licences.

3.3 Views of the Board

The Board believes that any estimate of the productive life of oil and gas wells is subject to uncertainty and would be influenced by a variety of geological and commercial factors. With regard to the original estimate by Westhill of 10 years' production from the 13-33 well, the Board notes the actual productive life is now estimated to be 14 to 15 years, which it considers to be representative of normal uncertainty considering the length of time many other nearby wells have produced. While the Board recognizes that Mr. Cook may have formed an impression about the productive life of the original well, it would not consider it to be in the public interest to cancel the licence for the well on that basis.

With regard to whether the remaining well licences should also be amended in order that the 11-33 and 12-33 wells are abandoned within the same period, the Board notes that Mr. Cook was aware since 1980 that two more wells had been drilled on his property. It was apparent from the Surface Rights Board Decision E63/78 that Mr. Cook could re-open the compensation issue if the life of the well should extend beyond the estimated 10-year life. Despite this, he did not approach the Surface Rights Board at any time to review his case. Additionally, evidence was presented that suggests Mr. Cook may have been notified prior to the drilling of the 11-33 and 12-33 wells. Nevertheless he did not object nor did he take the opportunity to raise the issue with the ERCB once the wells were

discovered. He apparently also did not contact the Surface Rights Board or the ERCB in 1988 when approached by Dome for permission to flowline production from the facility.

Based on this information, the Board believes that Corvair would be justified in expecting that Mr. Cook understood that the new wells drilled from the 13-33 site had extended the life of the lease significantly from Westhill's original prediction. Since Mr. Cook had not approached the Surface Rights Board or the ERCB, Corvair also had reason to believe that Mr. Cook did not object to the use of his land for either the 11-33 or the 12-33 wells when Corvair acquired the rights to the wells from Dome.

In consideration of the above, the Board does not believe that the cancellation or amendment of the well licences would be justified or that abandonment is warranted. However, it does believe that prudent planning and mitigative measures are necessary in order that impacts from the wells be minimized. The Board believes that if the 12-33 well remains in a suspended state until the time at which Mr. Cook intends to proceed with his development plans and the 13-33 well is abandoned, it would be appropriate to also direct the abandonment of the 12-33 well. This would remove much of the permanent equipment from the lease. The impacts associated with the remaining 11-33 well are discussed further in this report.

4 NEED FOR REDUCED SPACING AND THE PROPOSED WELLS

4.1 Views of the Applicant

Corvair submitted that the application for reduced spacing would extend the existing spacing for the Pool into the southern half of section 33. It stated that the 11-33 well is currently the best producing well in the Pool and has the lowest water production of all the wells. Although the reservoir has not been tested to the south and east of the 11-33 well, Corvair believed that the first two of the proposed wells to be drilled (6-33-51-25W4 and 10-33-51-25W4) would have a greater than 50 per cent chance of success.

Corvair submitted that it had entered into a minerals lease agreement with the mineral owners of section 33 (the City and the Province of Alberta) and that it was entitled to develop those minerals. It stated that the proposed wells would allow for the exploitation of the resources in the interests of itself, the City, and the Province of Alberta (the Province).

4.2 Views of the Interveners

The interveners did not dispute the need for the reduced spacing application or the proposed wells, and no argument was presented to counter Corvair's geological interpretation of section 33.

4.3 Views of the Board

The Board believes that there are sufficient geologic prospects to expect that the Pool can be extended and that if the wells were successful, they would represent a substantial monetary interest to the Province, the City, and the company. The Board accepts that there is a need for the reduced spacing and the proposed wells to exploit the potential resource and notes that the interveners did not dispute the need for the reduced spacing and proposed wells.

5 SURFACE LOCATION OF THE PROPOSED WELLS

5.1 Views of the Applicant

Corvair submitted that it had carefully considered a number of potential surface locations for the proposed wells before it settled on the existing 13-33 site. It had looked at potential locations on the south side of the North Saskatchewan River which would have involved less horizontal displacement during drilling, but discounted these for several reasons. First, a drilling location on the flood plain would present a hazard to the environment and would not likely be approved by Alberta Environment. Second, a location farther south, away from the river valley, would place the wells in close proximity to residential development along Windermere Road. Additionally, there are presently no nearby oil and gas processing facilities or pipelines on the south side of the river and development of a site there would create a new oil-field development where none currently exists.

Corvair stated that it also considered the existing Denison 3-4-51-25W4 location (the Denison 3-4 site), which already has four producing wells, as an alternative location. It did not consider this a viable alternative, however, as the horizontal displacement to the bottom-hole target areas for the wells would be approximately 500 m greater than from the proposed location and would result in an additional cost of approximately $150 000 per well. Further, this location would place the wells closer to the Riverside Heights subdivision where there are no treed areas to screen the wells. Corvair also considered an alternative location in the southwest corner of Mr. Cook's land, but rejected this as a viable alternative since it would create another well-site facility where one is not needed and would simply relocate the impacts to another area.

It was Corvair's submission that the proposed location for the wells at the existing 13-33 site was the best choice and in the spirit of the West Edmonton Inquiry Report which stressed consolidation of oil-field facilities and utilization of existing sites in order to minimize surface impacts.

5.2 Views of the Interveners

Mr. Cook argued that Corvair had not adequately considered alternative locations for the proposed wells and that the locations that were considered were prematurely rejected. He submitted that the Denison 3-4 site location represented a more intense consolidation of oil-field equipment than the 13-33 site and thus would be the more appropriate location for the proposed wells. It was argued that the cost to drill the wells from the Denison 3-4 site would be approximately $110 000 to $125 000 more per well than from the proposed location and that the Denison 3-4 site would not present any greater technical difficulties for directional drilling. Mr. Cook illustrated his point by referencing a well near Pigeon Lake (Lsd 10-2-47-1W5M) which had a horizontal displacement of 2986 m and true vertical depth of 1235 m. Mr. Cook stated that this displacement for an apparently economic well was considerably greater than the largest displacement proposed by Corvair, while the true vertical depth of the wells would differ by only 100 m and the production rates would be very similar.

Mr. Cook also argued that the estimated cost to flowline the production off site from the existing battery is less than estimated by Corvair. It was also submitted that the existing pipeline from the Denison 3-4 site to the battery at 6-4-51-25W4 would eliminate the costs of trucking, of building a pipeline from the 13-33 well site to the tie-in point to the 6-4 battery, and of purging the pipeline from the 13-33 well site to flow test oil to the battery. Further, it was submitted that the Denison 3-4 site

is located farther from residential development than the 13-33 well site would be if development occurred on Mr. Cook's lands.

Mr. Cook submitted that a second alternative location existed on the south side of the North Saskatchewan River. It was stated that there was ample room to locate a well site, maintain a proper separation distance from the river, and not encroach upon the residential development that exists along Windermere Road. An added benefit to Corvair would be the substantially reduced horizontal displacement at this alternative location.

Mr. d'Alquen indicated that he could not see any considerable difference in surface impact between locating the proposed wells at the 13-33 site or the Denison 3-4 site. The visual impact would be greater for the residences along River Heights Drive if the wells were drilled at the Denison 3-4 site, while he believed the odour problem would be compounded by the addition of the proposed wells at the 13-33 site.

Mr. Flewelling stated that he was neutral on the issue of the location for the proposed wells. His concern was over the potential for odours and the release of H_2S and he did not believe that a drilling location at the Denison 3-4 site would have any less impact than the proposed location. He indicated a preference for a location to the southwest of the proposed well site that would place the wells farther from the River Heights subdivision, into tree cover and below the crest of the riverbank.

5.3 Views of the Board

To assess an appropriate location for the proposed wells, the Board believes it must consider how the location would affect Mr. Cook, the area residents, other property owners in the area, and the environment as compared to possible impacts on Corvair. It must also consider whether mitigative measures are available to reduce these impacts to an acceptable level. The Board must further keep in mind the spirit and intent of the West Edmonton Inquiry Report. That report encouraged the industry to utilize and consolidate existing oil and gas facilities as much as possible in the area such that resource and urban development can co-exist and impact minimally on each other.

The Board believes that the proposed alternative locations on the south side of the North Saskatchewan River cannot be justified. The potential environmental impacts of a well site on the river flood plain would be serious and it is the Board's opinion that this type of industrial development near the river, immediately upstream from the City, is not appropriate. If a location farther south of the river were chosen, the Board foresees impacts from the wells on the residents along Windermere Road. It is also noted that there are no existing oil and gas facilities in this area and that the impacts and costs associated with trucking well effluent would be considerable. Therefore, locating one or more well sites on the south side of the river would require development of a new industrial site which would simply relocate impacts and would be contrary to the objectives of the West Edmonton Inquiry Report. The Board notes that Mr. Cook rejected a proposed site near the southwest corner of his property, in part because it did not meet with his wishes any more than the existing site and also because potential impacts would be imposed on nearby residents to the south. The Board concurs with this latter view.

The Board finds that of the sites considered at the hearing, both the Denison 3-4 site and the 13-33 well site are feasible surface locations for the proposed wells. The Board accepts the merits of the alternative Denison 3-4 site for drilling the new wells but believes the site poses several problems that

reduce its acceptability. The Board notes that this location is in full view of, and nearer to, the residences along River Heights Drive than is the proposed location. Further, directional drilling from the Denison 3-4 site would involve an additional average 500-m increase in horizontal displacement to the wells, considerably increasing both drilling and servicing costs.

The Board believes that, provided impacts can be reduced to an acceptable level, the 13-33 well site would be the most appropriate surface location for the proposed wells.

6 IMPACT OF THE PROPOSED WELLS

6.1 Views of the Applicant

Corvair submitted that the proposed surface location for the proposed wells was the most economically viable alternative and would cause the least amount of impact on the land surface and on area residents. It believed that drilling the wells from an existing location that has production facilities to handle the additional wells would only minimally increase the impacts that already exist. Respecting Mr. Cook's desire to build a home near the site and develop his land into a residential subdivision, Corvair believed that this could be accommodated by certain measures it would be prepared to employ. It submitted that if by drilling the proposed wells, fluid production were increased to 1600 m^3/mo, its commitment to pipeline the production from the 13-33 site would permit it to eliminate most of the existing production facilities. Corvair also committed to landscaping the lease area using trees, berming, and screening to reduce the visual and noise impacts from the site, and was prepared to comply with the requirements of the West Edmonton Inquiry Report in order that impacts be reduced as much as possible.

6.2 Views of the Interveners

Mr. Cook submitted that the drilling of the proposed wells at the 13-33 location would compound the problems and impacts that currently result from the existing wells and production facilities. His position was that as long as either the existing or the proposed wells were on the property, no amount of mitigation or reduction of impacts from the wells and related equipment on the lease would allow him to pursue his plans to build his home. He contended that even if the production facilities were reduced such that all that remained on the lease were screw pumps rather than pumpjack pumps on the two existing and five proposed wells, plus an associated electrical box to supply power to the pumps, he would still be affected to an unacceptable degree by noise from the wells, odours, and any work that would be required at this site by the operator.

Mr. d'Alquen and Mr. Flewelling stated that their main concern respecting the proposed location for the new wells was the potential for an increase in odours in the area and the potential health effects of H_2S and sulphur dioxide (SO_2) emissions. They contended that odours seemed to come predominantly from the south of Riverside Heights in the direction of the existing 13-33 battery. The addition of five wells to that battery would increase the odour problem and potential health effects on area residents. It was suggested that Corvair be required to comply with the West Edmonton Inquiry Report by landscaping and screening the location.

6.3 Views of the Board

The Board has already indicated in Section 5.3 that it believes the proposed 13-33 well location for these five new wells, while less than ideal, does represent the best available compromise between the needs of the applicant and the various interveners. Furthermore, it is the Board's view that with proper care and good design, the proposed wells can be developed with an acceptable level of impact on local residents and property owners.

The Board notes that Mr. Cook was generally unwilling to accept any compromise short of total removal of all wells and production facilities from his property. While this is, of course, Mr. Cook's prerogative, the Board believes that development of the area mineral resources can be accomplished without severely compromising the value of Mr. Cook's land for either a single residence or future higher density residential development. In coming to this view, the Board has attempted to weigh the needs of Mr. Cook against those of the owners of the mineral rights, of Corvair, and of the other area residents. In the Board's opinion, by implementing the development requirements as set out below and in Section 7, area impacts can be mitigated sufficiently that development of the proposed 13-33 well site provides the maximum public benefit at the least overall cost, and that such development would be within both the spirit and intent of the West Edmonton Inquiry Report.

In consideration of the proposed surface location and the likelihood that successful wells would extend operations for more than 15 years, the Board believes it is appropriate to compare it to other similar situations that exist in the West Edmonton area. The Board was encouraged by the participants at the hearing to view other locations in the area. One of the sites visited is operated by Leddy Exploration Limited, Lsd 2-30-52-25W4M (the Leddy site). In the Board's view, the Leddy site is an example of where the interests of both the mineral developer and the surface developer can be accommodated by effective planning and co-operation. The Leddy site is situated within the Lewis Estates subdivision and has been landscaped and screened by fencing and trees, and contains no associated production facilities. The two existing pumpjacks at this location are enclosed in a fenced area, painted with earth colours, are electrically driven, and emit very little noise or odour.

It was noted during the site visit that screw pumps had not been utilized at the Leddy site. The Board believes that screw pumps are not as reliable as conventional pumpjack pumps and there would be additional servicing costs and operational problems associated with screw pumps if used by Corvair for the type of production it is proposing. Based on this, the Board does not believe that it is necessary to impose the use of screw pumps at the proposed location at this time. However, the Board will review the merits of screw pumps in the event urban development encroaches upon the 13-33 well site. Since there was some question as to the timing of residential development on Mr. Cook's lands, the Board would also not require that Corvair immediately implement landscaping and screening measures. However, in the event that Mr. Cook proceeds with his plans to construct a home or to develop a residential subdivision, Corvair would be required to implement the following mitigative measures:

- a suitable sound barrier such as berming must be constructed around the inside perimeter of the location,

- the area surrounding the lease must be suitably landscaped, including trees, to reduce the visual impact,

- in addition to the present requirements that the lease site must be fenced with locked gates, the fence must be designed such that it will reduce the visual impact of the location,

- equipment must be housed to the maximum extent possible,

- housekeeping and painting must be of a high standard,

- electrification of the location must be in accordance with the neighbourhood electric system and must include underground wiring if such is in use in the area.

With regard to the concerns of Mr. d'Alquen and Mr. Flewelling, the Board accepts the maximum potential H_2S release rate of 0.008 cubic metres per second (m^3/s) calculated by Corvair and believes that at this rate, the drilling or production of the proposed wells would not present a safety hazard to area residents. The Board further accepts, based on the volumes of gas that would be flared from this site, that the resultant cumulative SO_2 emissions in the area would not present a safety or environmental hazard and would be well within Alberta air quality standards.

7 NEED FOR AND IMPACT OF THE PROPOSED BATTERY

7.1 Views of the Applicant

Corvair submitted that it was applying to construct a multi-well proration battery irrespective of the success of the development drilling program. It proposes to replace one of the existing separators with a 3-phase treater and add a 65-m^3 produced water storage tank. Corvair stated that the proposed battery modification could handle production from the existing and proposed wells. The construction could be accommodated on the existing site with minor relaxation of some equipment spacing requirements, and hence there would be no need to acquire additional land. In addition, this would allow Corvair to process its own production and eliminate most of the emulsion treating fee at the Denison 6-4 battery.

Corvair submitted that it would pipeline the fluid production to the Denison 6-4 battery if the development drilling were successful and established over 1600 m^3/mo of fluid production. Corvair stated that the economic justification for the two pipelines would result from eliminating the cost of trucking the oil and water to the Denison 6-4 battery.

Corvair estimated that the total gas produced at the site could increase to 6.10×10^3 m^3/d if all of the development wells were successful. It indicated that it has investigated the feasibility of conserving the gas. The nearest processing plant in the area, the Chevron Acheson Gas Plant, is approximately 16 km away. The closest solution gas tie-in point is at Lsd 13-14-52-26W4, over 11 km away from the 13-33 well site. Considering the relatively low volume of gas and a capital expenditure for facilities and pipelining estimated at $1 million, Corvair stated that gas conservation was uneconomic and planned to flare the gas at the 13-33 well site. Recognizing the potential for increased SO_2 emissions as a result of the increased volume of flared gas, Corvair commissioned a study of maximum ground-level concentrations of SO_2. The study, which considered the existing and potential gas flare rates at both the 13-33 site and the Denison 6-4 battery, indicated that the maximum 1-hour concentration would be substantially below the provincial standard of 0.17 parts per million.

In response to questioning, Corvair indicated that the Denison 6-4 battery would have the capacity to process all of the production, existing and potential, from its wells. However, if its battery application were denied, Corvair noted it would be in the unenviable position of having to negotiate processing fees without having an alternative. Corvair also indicated that relocating its battery to other locations on the Cook lands or, for that matter, to the south side of the Saskatchewan River, would only be moving the impact to a new area involving different people. Corvair stated it believed its facility could co-exist with residential development. It indicated that prior to its "open house" it was not aware of any odour complaints respecting its present facility.

7.2 Views of the Intervener

Mr. Cook submitted that the existing 13-33 battery is in the worst possible location insofar as surface development is concerned. He indicated that he had delayed his plans to construct a home on his land and suggested that the noise, truck traffic, flare, and odour problems cannot be mitigated to the point of being harmonious with residential development.

In his intervention, Mr. Cook submitted that if the proposed wells were denied, the facility could operate as it is for the remaining 1.5-year life of the 13-33 well. At that point, the production from the 11-33 well should be pipelined to a different location.

If additional development were to be permitted, Mr. Cook requested that the Board require that all production, existing and proposed, be pipelined to a different site off of Mr. Cook's lands. He further proposed gas conservation measures to eliminate the existing flare stack and suggested that approval of any development at the site would require provisions for landscaping, screening, and strict safety measures.

Mr. d'Alquen and Mr. Flewelling indicated that they have experienced odour problems but added that these problems were not persistent enough to have caused them to report them to the company or government agencies. They expressed concern about the additional flaring and SO_2 emissions that would result and stated that they favoured consolidation of the Corvair facilities with the existing Denison facilities at 6-4. They added, however, that they could not be sure that their position would be shared by all of the residents of Riverside Heights.

7.3 Views of the Board

The Board is satisfied that the existing production facilities are not capable of handling production from the proposed development wells on a permanent basis. It notes that Corvair wants to modify the facilities to a full treating proration battery to minimize treating costs but the Board does not believe that the modifications would be necessary from an operational point of view unless additional production is added by the new wells.

While it is difficult to determine the timing and extent of residential development on the Cook lands, it is almost certain that a serious conflict would result in the future if the facility continued to operate as a battery. The Board notes Corvair's commitment to pipeline all of the production to the Denison 6-4 battery provided the development wells result in an increase of total fluid production to 1600 m^3/mo. The Board believes, however, that any successful new well at the 13-33 well site would justify not only flowlining but also treating all production off site, since the completion of one or more of the proposed wells could significantly increase the life of the development. The Board believes that this

would satisfy its policies respecting consolidation of production facilities in the general West Edmonton area. The Board expects that elimination of the flare and production tanks at the 13-33 well site would also reduce residential nuisances, odours, and traffic, and that the only production facilities that would be required at the 13-33 well site are a small building to house a test separator and associated instrumentation and meters.

Having considered the impact of the existing production facilities, the development potential of Mr. Cook's lands, and the fact that alternative production facilities are available, the Board has concluded that the proposed production facility is not required nor is it in the best interests of the area residents. The existing production facilities at the 13-33 well site are adequate to permit post-drilling testing of the proposed development wells. If additional reserves are not established with the new wells, the facility could remain as it presently exists. However, if new reserves are discovered and any of the new wells successfully completed, Corvair would be expected to flowline all of the production, existing and new, to an alternative site. The Board believes this would greatly reduce the impact of oil production activity at the 13-33 well location and should allow for co-existence between resource and residential development of the Cook lands. The Board notes that the Denison 6-4 battery appears to be a viable alternative production facility; however, the Board would expect Corvair to investigate all the available options and would consider the most suitable in a separate application.

The Board agrees with Corvair that the economics of conserving the gas produced at both the Corvair and Denison sites does not justify the large capital expenditure required at this time. While it believes that Corvair's estimate of $1 million may be high, it is satisfied that the gas could be flared in the area until such time as the economics for gas conservation improve or until residential growth in the area is such that flaring would have to be eliminated for environmental and aesthetic reasons. In addition, the Board has reviewed the SO_2 ground-level concentration study conducted by Corvair and agrees that the flaring of the cumulative solution gas will not result in any violation of the provincial standards.

8 DECISION

The Board has carefully considered the applications made by Corvair and the concerns expressed by Mr. Cook and the area residents near the proposed 13-33 well site. The Board concludes that there is a need for the reduced spacing on the south half of section 33 and for the proposed wells. However, the Board does not accept the need for the proposed battery modifications. The Board believes that the existing 13-33 well facility could accommodate the production testing of the first and possibly second wells, and if any new well is found to be successful it will require Corvair to flowline the total production from all wells at the 13-33 site to a suitable off-site location. Testing of subsequent wells at the 13-33 well site could be done through the flowlines. The Board is prepared to approve the spacing and well licence applications subject to the following requirements:

- Corvair shall comply with its commitments made at the hearing and in its submissions to the Board.

- If any of the proposed wells establish additional production, Corvair shall construct a pipeline to a suitable production facility away from the 13-33 well site, and at the earliest convenience remove all unnecessary production equipment, including flares, from the 13-33 well site.

- If Mr. Cook, or any future rightful owner of the land, proceeds with residential development, Corvair will implement landscaping and screening measures as described in this report and in accordance with the West Edmonton Inquiry Report.

The Board approves the well licence applications and reduced spacing order. The licences and spacing order will be issued in due course. The Board denies the application for modification of the 13-33 battery, for reasons as stated in the report.

The Board denies Application 901203 to rescind well licence numbers 63496, 84329, and 85267 for reasons described in the report.

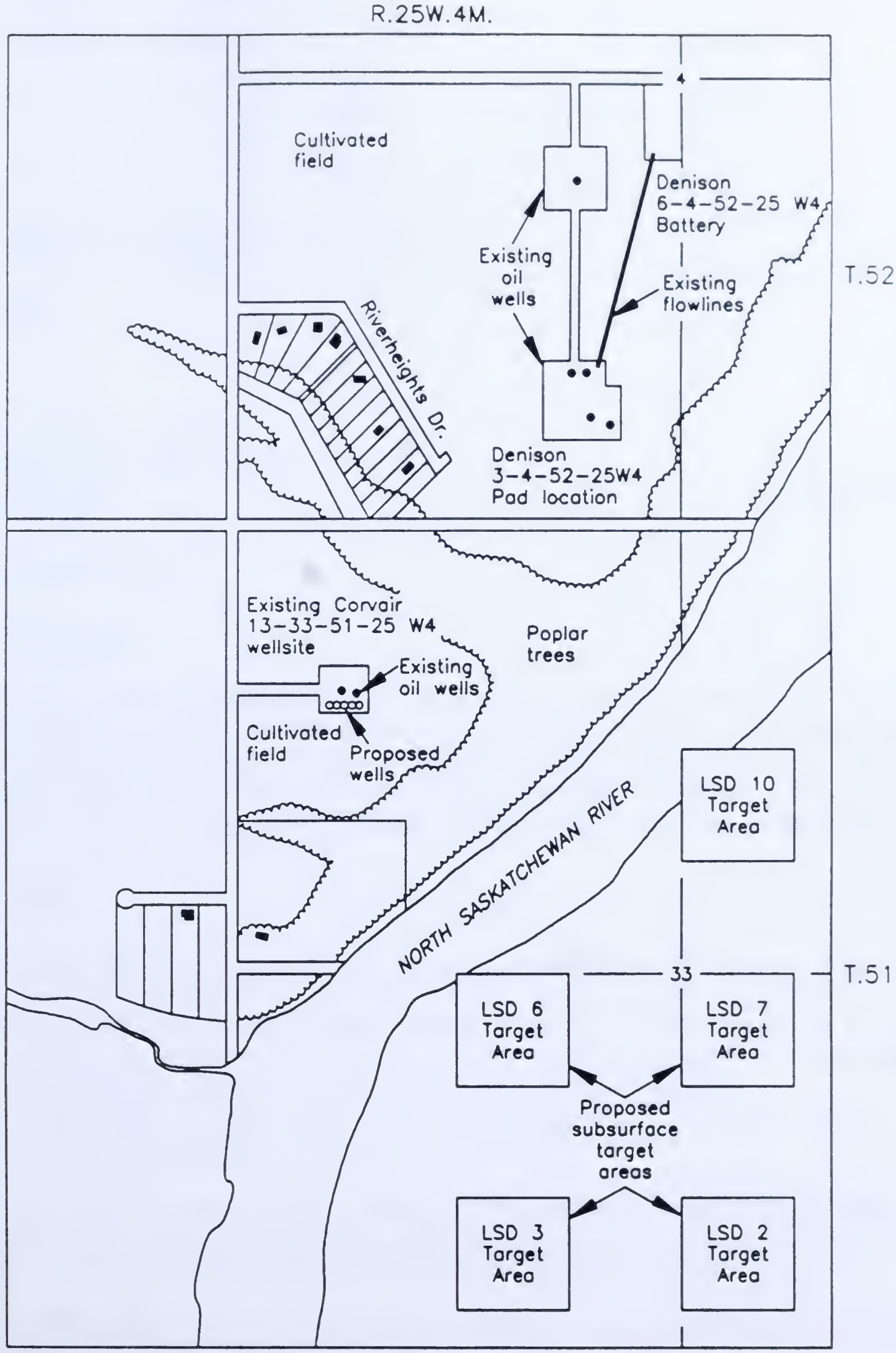
DATED at Calgary, Alberta, on 20 November 1990.

ENERGY RESOURCES CONSERVATION BOARD

F. J. Mink, P.Eng.
Board Member

B. F. Bietz, Ph.D.
Board Member

N. G. Berndtsson, P.Eng.
Acting Board Member



PROPOSED WELL LOCATIONS AND TARGET AREAS
Corvair Oils Ltd. 13-33-51-25 W4M
Applications No. 900909, 900910, 900911, 900912, 900913, 900965 and 900723

D90-13
ERCB

ENERGY RESOURCES CONSERVATION BOARD

Calgary, Alberta

HOME OIL COMPANY LIMITED
REDUCED DRILLING SPACING UNITS
WOOD RIVER FIELD

Decision D 90-14
Application 891717

1 INTRODUCTION

1.1 Application

Home Oil Company Limited (Home) applied pursuant to section 4.030 of the Oil and Gas Conservation Regulations (the Regulations) for an order establishing 32-hectare drilling spacing units (DSUs) comprising the east half and west half of the quarter section for the production of oil from the Nisku Formation within the southwest quarter of section 21, township 42, range 23, west of the 4th meridian (SW 1/4 Sec 21). The applicant requested the target areas for the DSUs be established in accordance with Board Order No. SU 1088.

1.2 Hearing

The original application for a change to a central target area in the SW 1/4 Sec 21 was scheduled to be considered at a public hearing on 20 June 1990. However, Home amended the application to request reduced spacing, which prompted several mineral owners affected by the application to request a deferral of the hearing. The Board granted the deferral and the revised application was considered at a public hearing in Calgary, Alberta, on 1 and 2 August 1990, by Board Members E. J. Morin, P.Eng. and F. J. Mink, P.Eng., and Acting Board Member C. A. Langlo, P.Geol. Those who appeared at the hearing are shown in the attached table.

Poco Petroleums Ltd. (Poco) gave evidence on behalf of both itself and Albercan Oil Corporation. Canadian Cometra, Inc. and Fossil Oil and Gas Limited did not file interventions to the application but did register as participants in the hearing for the purpose of cross-examination.

Elsie Williams filed a submission but did not give direct evidence. Counsel for Williams presented closing argument.

2 BACKGROUND

Development of the Nisku Formation in the north half of township 42, range 23 W4M (42-23 W4M) began in 1972 with the drilling of the well, HOL WOOD RIVER 16-28-42-23 W4M. Other wells were drilled in legal subdivisions (Lsd) 6-28 in 1973 and 14-21 in 1974. These wells were designated as the Wood River D-2 C Pool and in 1980 the Nisku Formation within the defined pool was unitized as the Wood River D-2 C Unit (Unit), operated by Home. In December 1987 Poco drilled a well adjacent to the Unit in Lsd 16-20 and the well was classified as a single well pool and designated the Wood River D-2 E Pool.

Subsequent wells were drilled in Lsds 6-21, 16-17, 13-21, and 4-21. Home considered the wells in Lsd 16-20, 14-21, and 6-21 to be completed in a separate pool and in August 1989 applied to have the pools coalesced and redesignated as one. The Board agreed in part and deleted the 6-21 and 14-21 wells from the D-2 C Pool and redesignated them as the D-2 F Pool. The 16-20 well, meanwhile, remained classified as a single well pool. A subsequent review in May 1990 resulted in the Board coalescing the D-2 E and D-2 F Pools and the DSUs containing the wells in Lsds 16-17 and 13-21. The redefined pool was designated as the D-2 E Pool. The 4-21 well drilled in July 1990 is also in the D-2 E Pool.

The D-2 E Pool as currently defined is developed on one quarter section (64-hectare) DSUs with a mix of target areas. The NW 1/4 Sec 21-42-23 contains a central target area in accordance with section 4.020, subsection (1) of the Regulations. This target area was established by the 14-21 well which was drilled on-target to the Nisku Formation prior to the establishment of corner target areas by Board Order No. SU 1088 (SU 1088). Target areas for the remaining DSUs are located in the NE Lsd in accordance with SU 1088.

The D-2 E Pool boundary as interpreted by the applicant, the mineral rights ownership, well locations, and target areas are shown on the attached figure.

3 ISSUE

The Board considers the principal issue of the hearing to be the need for reduced spacing. Factors relating to need include resource recovery, spacing regulations, and equity interests.

4 NEED FOR REDUCED SPACING

4.1 Applicant's View

4.1.1 Resource Recovery

Home submitted that the Nisku D-2 E Pool (E Pool) is an elongated and hydraulically isolated patch reef. It is considered to be a volumetric oil reservoir having a solution gas drive with potential for development of a minor primary gas cap drive mechanism as the pool is depleted. Home submitted that the E Pool did not appear to be in communication with the Leduc (D-3) aquifer. The applicant stated that its volumetric estimate of oil in place is 1.3×10^6 m^3 which is based on an average porosity of 10 per cent for the pool.

Home submitted that approval of its application would permit production of the 6-21 and the 4-21 wells, which would result in improved recovery from the pool and reduce inequitable lease line drainage of its lands. The applicant stated that for this pool, SU 1088 spacing is too coarse to maximize recovery and that approval of its application would be beneficial with respect to both primary and secondary recovery operations. Home argued that on primary recovery, a higher well density will provide a more uniform gas cap advance by reducing the magnitude of producing well pressure sinks, thereby reducing the impact of coning on reservoir sweep. The applicant also stated that reduced spacing will maximize secondary recovery by permitting proper reservoir delineation, by reducing injectant coning and the resulting denigration of gravity stable flood fronts, and by promoting improved volumetric sweep of lower quality reservoir rock on the edges of the pool. Home stated that it is important that both the 6-21 and 4-21 wells be permitted to produce.

The applicant did not conduct any depletion studies but did present general evidence to support its contention that incremental recovery would occur, and also noted Poco's depletion study which showed a small improvement in overall recovery. Home stated that it believed the actual incremental recovery would likely increase by 10 to 15 per cent which is significantly higher than the 1.2 per cent predicted by Poco. It noted that the Poco study did not include production from the 6-21 well and past performance of similar pools on reduced spacing showed incremental recoveries higher than those predicted by Poco. In Home's opinion, failure to produce the 6-21 well will result in a loss of oil recovery from the flank of the pool in Lsds 5 and 6 of section 21.

Home argued that section 4.030, subsection (3)(a) of the Regulations requires an applicant to show only that improved recovery will be obtained and does not require a determination of the magnitude of that improvement, or a discussion of the economics. Home concluded that on the basis of the evidence presented in its submission and the results of Poco's study, improved recovery would occur and it had therefore met the criteria for reduced spacing.

Home acknowledged that the E Pool should be unitized and a secondary recovery scheme be implemented as soon as possible to ensure maximum recovery from the pool. Home stated it would initiate unitization discussions with all the affected parties in a timely manner but was doubtful that an agreement could be reached within a year because of the large number of participants and the resulting complexity of the negotiations. Consequently, production from the pool would continue to be by primary depletion for some time.

On a related matter, the applicant requested that future allowable determination continue to be independent of the drilling spacing unit size. This would permit both the 6-21 and 4-21 wells to produce a maximum of 50 m^3/d of oil each, even though the area of their respective DSUs would be half that of other wells in the pool. In response to questioning, the applicant stated that the 50 m^3/d/well allowable was appropriate based on well performance and, presupposing that secondary recovery is instituted, did not foresee any conservation problems arising from the production of wells at this rate.

4.1.2 Spacing Regulations and Equity Interests

Home submitted that SU 1088 spacing is not appropriate in this pool because it seriously prejudices the rights of the mineral owners to recover their share of resources. Home stated it understood the reasons for SU 1088 spacing and was not suggesting that its merits be reconsidered on a provincial basis. However, it considered the premise that opportunities for a fair share of production lost under

SU 1088 spacing in one area being offset by benefits realized in other areas of the Province is not appropriate in this case because affected parties include several freehold mineral owners who do not have the land holdings required to benefit from such opportunities.

The applicant estimated 95 per cent of the primary recoverable oil in place (ROIP) of the E Pool underlies the west half of section 21 with 55 per cent of the ROIP underlying the SW 1/4 Sec 21. Home stated that SU 1088 spacing has created a situation whereby the owners of the SW 1/4 do not have an on-target location to access the reserves under their land. Yet the operators of the NE 1/4 Sec 17-42-23 and the NE 1/4 Sec 20-42-23 have been able to legally drill the wells 16-17 and 16-20 in the extreme corners of their respective target areas and have obtained very productive wells while only contributing an estimated 5 per cent of ROIP to the pool. Home contended that continued production of these wells at rates which do not reflect their reserve base facilitates continued drainage of reserves from the area of application. Home stated that in its view this is clearly inequitable and contrary to the intent of the Oil and Gas Conservation Act. The applicant submitted that unitization of the E Pool would address some of the equity concerns, but drainage would continue to occur during the period of negotiation. Home maintained that the approval of its application would not adversely affect the offset mineral owners because drainage would continue to be in favour of the adjacent leases and that the offset owners have the same opportunity to apply for reduced spacing should they wish.

5 INTERVENERS' VIEWS - IN SUPPORT OF THE APPLICATION

5.1 Joyce Bellous

Joyce Bellous appeared on behalf of herself and the other mineral owners in the SW 1/4 Sec 21 for the purpose of supporting the application for reduced spacing. Bellous stated that she had been advised by Home that a large portion of their lands was underlain by the E Pool and would continue to suffer substantial drainage unless something was done. Bellous stated she felt the rights of the freehold owners have not been adequately considered in the issues surrounding the application and existing well spacing rules. She stated that approval of the application would permit the freehold mineral owners an opportunity to enjoy the benefit of resource ownership which she believed had not been afforded to them to date.

6 INTERVENERS' VIEWS - IN OPPOSITION TO THE APPLICATION

6.1 Poco Petroleums Ltd. and Albercan Oil Corporation

Poco submitted maps which reflected similar pool configuration and net pay values to that of the applicant, but also showed a series of isolated highs on the reef crown. Poco submitted a depletion study of the E Pool to identify the effects of 32-hectare spacing. It estimated the E Pool to contain 910×10^3 m^3 of oil in place, of which 415×10^3 m^3 would be recoverable. In addition, the depletion study concluded that the subject pool is not a closed system but is in communication with the underlying regional Cooking Lake aquifer, although the extent of the communication is unknown.

Poco submitted that it was opposed to the application because reduced spacing is not required to recover the oil reserves from the E Pool. Poco noted that its depletion study showed an increase in total pool recovery of only 1.2 per cent of the original oil in place over a 20-year period, and concluded that the existing spacing regulations should be retained while the pool is being competitively operated. Poco stated that the 6-21 well was excluded from its reservoir study because the well's

ability to produce was unclear; consequently, it based its pool depletion predictions on the production of the 4-21 well only. Further, Poco stated that in a non-competitive operation an incremental recovery of 1.2 per cent would likely be uneconomic and a well would not be drilled to specifically capture those reserves. Therefore, Poco believed that the application failed to meet the requirements of section 4.030(3)(a) of the Regulations.

Poco submitted that secondary recovery should be implemented as soon as possible. While the depletion study assumed that the aquifer will maintain the E Pool pressure naturally, Poco conceded that make-up fluid injection may be required. Poco further submitted that unitization of the pool is imperative and should be proceeded with immediately, as it sees operational, conservation, and economic benefits regardless of the final depletion method selected for the pool.

Poco submitted that although drainage of reserves had occurred as a result of production of the 16-20 well, such drainage is the right of the owner of the discovery well since it assumed the greater risk in discovering the pool. In addition, it said the current drainage is most likely a result of Home's 13-21 well and not from the 16-20 well or PCP's well in Lsd 16-17. Poco argued that the applicant had an equal opportunity to produce its share of reserves through the existing well in Lsd 6-21 and by not doing so had created much of the problem itself. Poco further stated that the 6-21 well was economic to produce, as shown by Poco's economic analysis of the rates and projected tie-in costs quoted by the applicant.

Finally, Poco expressed concern that the applicant's request to maintain the 50 m^3/d/well allowable for both the 4-21 and 6-21 wells would permit the production of potentially twice as much oil from the SW 1/4 Sec 21 as from the adjacent lands. Poco stated that applying the 50 m^3/d allowable on a DSU basis is more equitable with reduced drilling spacing units.

6.2 PanCanadian Petroleum Ltd.

PCP stated that it is the owner and operator of the well in the NE 1/4 Sec 17-42-23 W4M. The on-target Nisku oil well in Lsd 16-17 was drilled in October 1989, and is capable of producing the current well allowable of 50 m^3/d. PCP drilled the 16-17 well under SU 1088 regulations with the expectation that offset drilling spacing units would be subject to the same spacing. It further submitted that approval of the application would prejudice the right of PCP to capture its reserves as allowed under SU 1088 by permitting the production of two wells in the SW 1/4 Sec 21, each with a 50 m^3/d allowable. PCP acknowledged Home's right to drill an off-target well in its drilling spacing unit, but felt strongly that it be produced under the existing penalty provisions which would limit its production to a maximum of 25 m^3/d of oil. PCP submitted that this rate would still be economic. In response to questioning, PCP agreed that unitization should take place as soon as possible and a secondary recovery scheme be put in place without undue delay to maximize pool recovery.

6.3 Elsie Williams

Williams represented the mineral rights owners in the NW 1/4 Sec 21. Williams stated Home had failed to prove that reduced spacing would improve recovery from the E Pool and suggested that the improved recovery argument was nothing more than an attempt to justify the application under the Regulations. Williams submitted that all of the benefits associated with improved recovery from the 4-21 well would be realized without approval of the application. She stated that approval of the application would promote drainage from the NW 1/4 Sec 21 by permitting the 16-20 and 6-21 wells

to produce at rates up to 50 m^3/d each. Williams further stated that existing well spacing conforms to the current legislation and the resulting drainage is a realization of the rule of capture. Williams submitted that the best solution would be to deny the application and allow unitization discussions to proceed.

6.4 Board's Views

6.4.1 Resource Recovery

The Board notes that there was general agreement among the participants as to the overall configuration of the E Pool. However, distribution of reserves between tracts was based on seismic information which was not submitted or discussed in detail at the hearing. There was some suggestion that the southern extension of the pool would be beyond the boundaries shown in the attached figure. Volumetric estimates of oil in place range from 910 x 10^3 m^3 to 1.3 x 10^6 m^3 which the Board believes are in reasonable agreement and reasonably accurate at this stage of the pool's depletion. Also, the Board notes that there was general agreement that some form of secondary recovery scheme is required and should be put in place as soon as possible. There was a difference of opinion as to the existence of a bottom water drive and therefore the nature of the secondary scheme that will be required. However, this is not considered by the Board to be a major concern since, as additional production is taken from the pool, the reservoir drive mechanism will be better understood and secondary recovery can be tailored to complement whatever natural reservoir drive exists. Finally, the Board notes that all participants agree that the E Pool should be unitized and Home and Poco both expect that up to a year may be required to complete that process.

Until secondary recovery is implemented, the E Pool will be operated on primary depletion. Accordingly, the application for reduced spacing must be considered to a large extent on this basis. The Board notes that a working agreement or unitization is required before a secondary recovery scheme is implemented, and that to a large degree many inequities or perceived inequities would be resolved through this process. However, the Board is aware that in unit negotiations both productive capacity and reserves are commonly considered in determining tract factors. Accordingly, the existence and magnitude of well allowables for the SW 1/4 Sec 21 are important to unit participants including the applicant.

The Board notes that Home did not quantify the incremental recovery expected if the application is approved. In this instance the Board believes that much of the improved recovery will occur as a result of production from the 4-21 well and that this will occur regardless of the size of the DSU. However, the Board sees an advantage to reduced spacing because it will permit the 6-21 well to produce and recover oil from the pool which may not be captured by the better quality wells. Also, reduced spacing in this case addresses what the Board considers to be other serious deficiencies in regulation of the pool.

The Board is satisfied that in this instance it is reasonable to expect no additional wellbores would be drilled within the currently defined pool if the reduced spacing application is approved. Given the evidence, the Board is satisfied that sufficient incremental recovery would be obtained by production of all wells currently drilled into the pool. It notes that the 4-21 well was drilled notwithstanding the disposition of this application and would be produced under penalty if reduced spacing is denied. The Board believes that the Poco depletion study was pessimistic about the overall recovery from the reservoir and prospects of production from 6-21, although it would not expect the improved recovery

to be as high as projected by the applicant. In the Board's view, it is reasonable to expect some production from the 6-21 well and, given its location, this will result in incremental recovery above that projected in the Poco study.

Section 4.030, subsection (3)(a) of the Regulations requires an applicant for reduced spacing to show that improved recovery will be obtained and section 15.160 requires the applicant to provide a tabulation of the economics of development on the existing spacing as well as the reduced spacing units. Although the Board believes that consideration must be given to whether or not the incremental recovery obtained by reduced spacing would be economic, the Board does not believe that in this case economics must be the determining factor.

6.4.2 Spacing Regulations and Equity

With respect to SU 1088, the Board is satisfied that it serves to minimize the conflict between surface land use and the petroleum industry on a provincial basis. In the Board's view SU 1088 does not preclude special consideration of equity issues where traditional central target areas and corner target areas interface. In this case, the Board finds that the mix of corner and central target areas, the physical location of the pool underneath the respective drilling spacing units, and the location of the offset wells relative to lease lines are a unique combination of factors which have led to significant drainage of the applicant's land. In general, if all the participants in the application enjoyed mineral leases throughout the Province, then the premise of SU 1088 that opportunities lost in one pool would be gained in another would apply. However, this is clearly not the case with this application as the freehold mineral owners testified that these are the only mineral rights they have.

Production data submitted during the hearing clearly show that currently 150 m^3/d of oil is being produced from offsetting spacing units while the SW 1/4 Sec 21 is limited to 25 m^3/d if the 4-21 well is produced under SU 1088 spacing. Considering the SW 1/4 of 21 may contain up to 55 per cent of the ROIP of the pool, the Board believes a change in spacing will reduce the drainage and provide the owners of the SW 1/4 Sec 21 an opportunity to enjoy the benefits of their mineral ownership.

The Board notes that current pressure data show the reservoir pressure to be less than its bubble point and the Board is concerned that continued operation for an extended period under primary production will harm future recovery under a secondary scheme and result in conservation losses. It also notes the 50 m^3/d/well allowable was established when there were only three producing wells in the pool and may not be appropriate should the number of producing wells increase to five. The existing allowables are assigned on a per well basis and the Board believes that is appropriate. However, it notes that a joint submission addressing depletion strategy and secondary recovery is required from the operators in the E Pool no later than 1 December 1990. Should the depletion study or well performance show that production at the current allowable is having an adverse effect on resource conservation, the Board expects to reduce the pool withdrawal rate. The Board agrees with the applicants that the E Pool should be unitized without delay but believes the estimated 1-year time period to complete a unit agreement is excessive. In this regard, the Board encourages all parties to work towards an early agreement.

7 CONCLUSIONS

Based on the evidence submitted, the Board is satisfied that the E Pool is unique in that it contains a wide variety of mineral ownership and demonstrates the drawbacks of mixed target areas. The Board is satisfied that reduced spacing will improve recovery and address the concerns associated with mixed targets as well as resolve some of the inequities currently being experienced by the freehold mineral owners in the SW 1/4 Sec 21. Therefore, the Board is prepared to approve the application for reduced spacing.

8 DECISION

The Board approves Application 891717 by Home Oil Company Limited for 32-hectare drilling spacing units in the SW 1/4 Sec 21-42-23 W4M and the continued sharing of the pool allowable equally by all wells.

Dated at Calgary, Alberta, on 1 October 1990.

ENERGY RESOURCES CONSERVATION BOARD

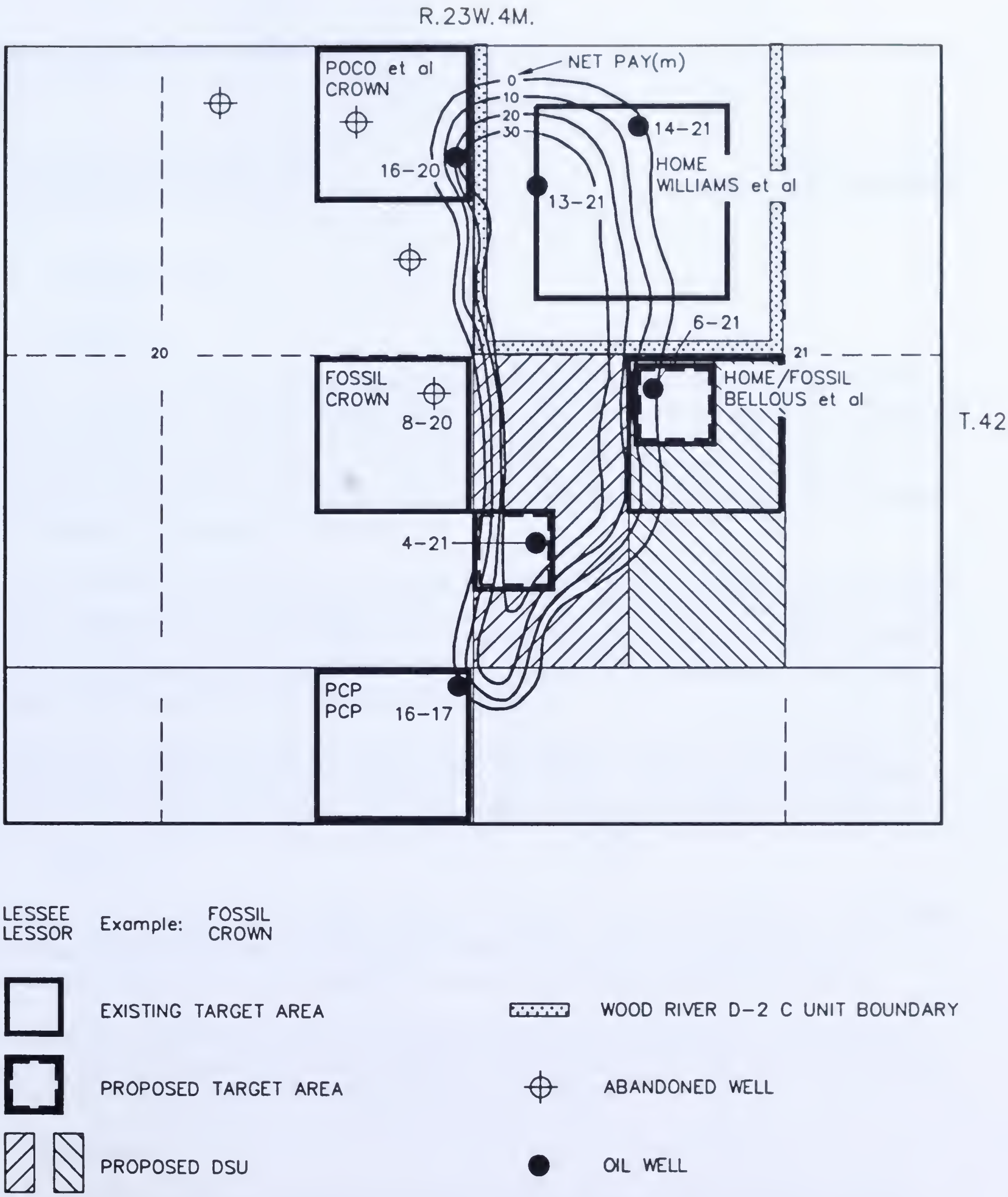
E. J. Morin, P.Eng.
Board Member

F. J. Mink, P.Eng.
Board Member

C. A. Langlo, P.Geol.
Acting Board Member

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Home Oil Company Limited (Home) D. Hart	D. Bertram, P.Eng.
Poco Petroleums Ltd. and Albercan Oil Corporation (Poco) K. Miller	M. Smith, P.Eng. R. Robertson, P.Geol. both of Poco Petroleums Ltd. B. Solc, P.Eng. of DPS Resources Ltd. S. Beveridge, P.Eng of Beveridge Engineering Ltd.
PanCanadian Petroleum Ltd. (PCP) P. Murray	M. Minhas, P.Eng.
Fossil Oil and Gas Ltd. (Fossil) K. Farries, P.Eng.	K. Farries, P.Eng. of Farries Engineering (1977) Ltd.
Canadian Cometra, Inc. G. Burden	G. Burden
Elsie Williams (Williams) R. A. Neufeld	
Joyce Bellous (Bellous) J. B. Ballem	Joyce Bellous
Energy Resources Conservation Board staff L. A. Schmidt, C.E.T. T. Dowsley, P.Eng. A. Beken, P.Geol. R. Heggie	



HOME'S NET OIL PAY – NISKU D-2 E POOL
Application No. 891717

D 90-14
ERCB

ENERGY RESOURCES CONSERVATION BOARD
Calgary Alberta

BOW VALLEY INDUSTRIES LTD. — Decision D 90-15
LONG-TERM GAS REMOVAL — Application 890715

1 INTRODUCTION

1.1 Application

Bow Valley Industries Ltd., as agent for Chesapeake Resources Ltd. (now Webex Oil & Gas Ltd.), Inverness Petroleum Ltd., Northstar Energy Corporation, and Universal Explorations Ltd., applied for a permit authorizing the removal of 1.1 billion cubic metres of natural gas from the province over a 15-year term commencing on the later of 1 November 1990 or the date of first deliveries. The maximum daily and annual volumes of gas to be removed under the permit would be 250.5 thousand and 91.5 million cubic metres, respectively.

The proposed permit would allow gas to be sold to Indeck Gas Supply Corporation for use as fuel for a gas-fired cogeneration plant located in the state of New York. The electric power generated at the plant would be sold to Niagara Mohawk Power Corporation (Niagara Mohawk) as part of a system supply serving residential, commercial, and industrial customers in the northeastern United States. The steam would be sold to the International Paper Company.

The gas would be transported from the Alberta border at Empress to Niagara Falls, Ontario, by TransCanada PipeLines Limited, and from the international border to the cogeneration facilities by National Fuel Gas Supply Corporation, CNG Transmission Corporation, and Niagara Mohawk.

1.2 Hearing

The application was considered at a public hearing in Calgary, Alberta, on 24 September 1990, before Board Members G. J. DeSorcy, P.Eng., and F. J. Mink, P.Eng., and Acting Board Member C. A. Langlo, P.Geol. Those who appeared at the hearing are listed on the following table.

At the conclusion of the hearing, the Board announced that it would be prepared to approve the application and would request the necessary Order in Council. This report summarizes the evidence received at the hearing and gives the reasons for the Board decision.

1.3 Interventions

The Board received submissions from Direct Energy Marketing Limited, Esso Resources Canada Limited, FSC Resources Limited, and Indeck Gas Supply Corporation. None of the submissions opposed the application. The first two parties noted above did not appear at the hearing. FSC Resources Limited registered as an interested party but did not raise any concerns, participate in cross-examination, or present final argument. Indeck Gas Supply Corporation was represented by the applicants' Counsel, Mr. K. F. Miller.

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives	Witnesses
Bow Valley Industries Ltd. K. F. Miller	W. L. Hodgson of Inverness Petroleum Ltd. G. B. Mack of Indeck Energy Services, Inc. J. D. McCormick of Webex Oil & Gas Ltd. D. A. Mercier of Universal Explorations Ltd. R. B. Pardy of Northstar Energy Corporation Dr. G. C. Watkins of DataMetrics Limited
FSC Resources Limited S. H. Lockwood	
Energy Resources Conservation Board staff K. Fisher G. Habib	

1.4 Jurisdictional Matters

Under section 8 of the Gas Resources Preservation Act (the Act), the Board is charged with an obligation to consider

(a) the present and future needs of persons in Alberta,

(b) the established reserves and the trends in growth and discovery of reserves of gas or propane in Alberta, and

(c) any other matters considered relevant by the Board.

Given the evidence, the Board is satisfied that the applicants have sufficient reserves to meet the terms of the permit and that the volumes are surplus to Alberta's requirements under the terms set out in Report 87-A. Among other considerations, the Board has a responsibility under section 8(c) of the

Act to satisfy itself that the sale is made at arm's length and the price is based on prevailing market conditions and is sensitive to changes in those conditions throughout the permit term.

2 ISSUES

In this instance, the Board considers the only issue to be whether or not the pricing arrangements would be sensitive to market conditions throughout the term of the sales contract.

3 VIEWS OF THE APPLICANTS

The applicants argued that the price to be paid for the gas would be sensitive to market conditions. They noted that the initial base price has been established at US $1.67 per thousand cubic feet of gas, which is significantly above spot gas prices available to the producers. The contract specifies that the base price would be escalated at an annual rate of 3 per cent, and would also be subject to adjustments resulting in a producer bonus. The applicants believe that the bonus constitutes the flexible, market-sensitive portion of the pricing mechanism. The producer bonus has floor and ceiling conditions to provide the predictability needed to secure financing for the cogeneration plant.

According to the applicants, the bonus mechanism works by paying a premium on the gas price in relation to the difference between the actual price paid for the electricity by Niagara Mohawk and the floor provision of the contract. The price to be paid for the electricity is a function of Niagara Mohawk's long-range avoided cost for power. The applicants were of the view that the avoided costs would be unlikely to decline because of continuing growth in demand for electrical power in the New York area. The project is currently receiving the floor price for the electricity generated, and it was anticipated that the producer bonus would be triggered within 18 to 24 months by higher avoided costs. The price ceiling in the contract would allow bonus increases of a maximum of US $3.75 over the escalated price by the end of the term of the permit.

The applicants also argued that the sales contract is acceptable because the initial price of the gas is set at a premium level which is more than they would currently receive for spot, firm 1-year, or alternative long-term markets. Moreover, the price would only escalate, contrary to the trend of continually declining prices of the past several years.

The annual escalator and producer bonus are calculated on gas at the Alberta border, which eliminates the risk, to producers, of downstream pipeline costs. The applicants noted that the contract provides a 94 per cent take-or-pay provision, and the security of actual facilities, to guarantee performance. The applicants concluded that the proposed sale provides a needed stable element in their market portfolios which would offset other more volatile sales and assist in their goal to diversify as much as possible.

In summary, the applicants concluded that the gas marketing arrangements under the proposed permit would be in the public interest of Alberta and requested that the application be approved.

4 VIEWS OF THE BOARD

As indicated at the hearing, the Board is satisfied that the proposed sale is in the public interest and should be approved. Given the evidence provided at the hearing, the Board believes the sale would represent a new and viable market for Alberta gas. The existence of take-or-pay provisions in the sales contract ensures the performance of the purchaser. The sales contract pricing provisions appear reasonable. The bonus mechanism provides for sharing of project revenues with the producers through adjustments to the gas price. Such adjustments are expected to reflect future changes in the firm long-term price of gas available in the market area. Given the current demand for electricity in the state of New York, the Board agrees with the applicants that there is a reasonable likelihood that the producer bonus could be earned within 24 months.

5 DECISION

Having regard for the evidence presented and the conclusions summarized above, the Board is satisfied that the proposed sale would be in the public interest of Alberta. The Board is therefore prepared, with the approval of the Lieutenant Governor in Council, to issue the requested permit.

DATED at Calgary, Alberta on 22 October 1990.

ENERGY RESOURCES CONSERVATION BOARD

G J DeSorcy

G. J. DeSorcy, P.Eng.
Chairman

F. J. Mink, P.Eng.
Board Member

Langlo

C. A. Langlo, P.Geol.
Acting Board Member

ENERGY RESOURCES CONSERVATION BOARD

Calgary, Alberta

RANCHMEN'S RESOURCES LTD.
REVIEW OF WELL LICENCE
KNOPCIK FIELD

Decision Report D 90-16
Application 901312

1 INTRODUCTION

1.1 Application and Intervention

On 3 May 1990 Ranchmen's Resources Ltd. (Ranchmen's) made application to the Energy Resources Conservation Board (the Board) to licence the proposed well, RANCHMEN'S ET AL KNOPCIK 7-19-74-11 (the well), to obtain production from the Doig Formation. The application was processed routinely by Board staff and Well Licence No. 0144089 was issued on 7 May 1990.

After the well was drilled and cased, but before it was completed and tested, adjacent landowners expressed concerns to staff of the Board's Grande Prairie Area Office, including the fact that the drilling of the well had proceeded against their wishes. Later, these concerns were confirmed in writing and a Board hearing to review the matter was requested. Upon being notified of the situation, Ranchmen's suspended the well pending completion of the review.

1.2 Hearing

A public review of the well licence was held at the offices of the Board in Grande Prairie, Alberta, on 27 September 1990, before Board Member E. J. Morin, P.Eng.

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Ranchmen's Resources Ltd. (Ranchmen's) R. A. Neufeld	R. Rieken, P.Eng. J. Shand
Adjacent Landowners (Interveners) R. L. Boonstra Rev. W. A. Ludwig B. D. Ludwig F. Ludwig	
Energy Resources Conservation Board staff N. F. Lord, C.E.T.	

2 ISSUES

The Panel considers the issues with respect to the application to be

- the need for the well, and
- the impact of the well.

3 CONSIDERATION OF THE APPLICATION

3.1 Views of Ranchmen's

Ranchmen's submitted that it had originally proposed to drill the well in the northeast quarter of section 19-74-11 W6M. In attempting to secure a surface lease from the Ludwigs, who own this quarter, Ranchmen's became aware of their opposition to the drilling of a well. Upon re-evaluation of the geology, Ranchmen's concluded it could drill a successful well from a surface location in the southeast quarter of section 19. Ranchmen's stated that at the time it believed this relocation of the well site would alleviate the concerns and objections of the interveners as it understood the interveners' concerns to be for the drilling of a well on land that they owned.

Ranchmen's submitted it successfully secured a surface lease for the proposed well in Lsd 7-19-74-11 W6M and then proceeded to obtain a well licence and fulfil Board requirements respecting emergency planning. All of the interveners were included within the emergency response planning zone proposed by Ranchmen's. However, the interveners refused both hand and registered mail delivery of the plans. Therefore, Ranchmen's arranged for an RCMP escort in case a real emergency developed, and proceeded with the drilling of the well. Ranchmen's stated it believed it had fulfilled all ERCB requirements and had conducted its operations to date in a manner consistent with good oil-field practice.

As holder of the mineral rights to section 19-74-11 W6M, Ranchmen's submitted it had a need for the well to capture any reserves which may underlie the section and which Ranchmen's could readily sell on the spot market. Further, Ranchmen's stated that log analysis of the well showed that its main objective, the Doig, was not productive. However, commercial production may be present in the Halfway Formation (Halfway). This could not be confirmed, however, until the well was tested. Those test results would supply the production and reservoir information which was required to determine Ranchmen's plans for future development in the area and the well itself. The Halfway Formation gas is expected to contain a maximum 4.6 per cent hydrogen sulphide.

Regarding the impact of the well, Ranchmen's stated the drilling of the well had proceeded routinely and without incident. Respecting any future impacts should the well prove productive from the Halfway, Ranchmen's was willing to implement mitigative measures to reduce any impacts to a minimum. These could include relocation of the access road, fencing of the well site, and consideration of various production equipment alternatives including locating these off site away from the interveners' residences. Ranchmen's was willing to consult with the interveners to discuss further mitigative measures. However, these were all dependent on the test results from the well. Additionally, if the well proved uneconomic, Ranchmen's would abandon it and reclaim the well site.

Ranchmen's described the completion and testing operations in detail and confirmed it was prepared to give consideration to the concerns of the interveners during these activities. The completion and

testing of the well would require 16 to 18 days, after which Ranchmen's would have the information it needed to reach a conclusion regarding the abandonment, suspension, or production of the well.

3.2 Views of the Interveners

The interveners stated they had originally voiced their concerns to Ranchmen's and ERCB staff in March of 1990 to the well proposed in the northeast quarter of section 19. They submitted that the movement of the well site to the adjacent quarter section had not alleviated their concerns and objections to the drilling of the well. They contended that Ranchmen's had been amiss in assuming that relocation of the well to a site in close proximity to their lands would rectify the situation.

The interveners submitted that while they could recognize Ranchmen's need and desire to develop the reserves that might exist in section 19, doing so was of no benefit to themselves.

The interveners submitted that the drilling of the well had already caused them adverse impact stemming from such things as dust, noise, and odours. The increased traffic and existence of the well site also raised concerns for the safety of their children. Further, they had a fundamental objection to what they considered to be an industrial intrusion in an area where they were attempting to develop a specific lifestyle. Considerable time, funds, and effort had been expended with the long-term goal of developing an area where they could establish a Christian community without social, industrial, or political intervention. Given this perspective, the drilling of a well in the area was not a situation which could be dealt with and made acceptable through the implementation of mitigative measures.

The interveners therefore requested that the Board order the well be abandoned.

3.3 Views of the Panel

The Panel accepts that Ranchmen's, as holder of the mineral lease for section 19, has a right to explore for and develop any reserves which may underlie the section. Given this, the Panel believes the well is needed, provided that its impacts are not so great as to preclude the drilling, testing, and production of the well.

The Panel recognizes that during the drilling of the well the interveners may have experienced some negative impacts from noise, dust, and traffic. However, given that the drilling of the well proceeded routinely and without incident, the Panel does not expect that these would have been of such magnitude as to be more than a general nuisance and inconvenience. In retrospect, however, it is unfortunate that Ranchmen's and the interveners were not able to address the residents' concerns more constructively. For example, if the access road had been relocated for the drilling of the well as Ranchmen's now propose for the permanent production operation, many of the interveners' concerns for dust, traffic, and safety of their children would have been minimized.

With respect to the completion and testing of the well, the Panel notes that Ranchmen's has prepared detailed plans. The Panel has reviewed these and concludes that the completion and testing of the well does not represent a potential hazard or significant nuisance and inconvenience to the interveners. Additionally, Ranchmen's are prepared to accommodate the interveners' concerns in these activities as much as is practical. Under these circumstances, and given that the completion and testing is required to establish the potential of the well and is expected to require no more than 16 to 18 days to complete, the Panel concludes that those operations should proceed.

The Panel notes that Ranchmen's was unable to describe a production scenario for the well with much certainty, as the productive capacity, type of produced fluids, and reservoir characteristics are unknown. The Panel believes that it is the permanent production operation which may have the largest impact on the interveners. Accordingly, it cannot render a decision respecting the impacts of the well and whether or not they can be mitigated, until the production situation is known.

After the well has been completed and tested, if Ranchmen's proposes to place the well on permanent production or suspend the well, the hearing should be reopened at the request of the interveners to consider the proposed operations and steps that should be taken to mitigate their impacts, or if the impacts are so great as to require the abandonment of the well. The Panel notes the well may be non-productive, in which case it would be abandoned.

4 RECOMMENDATIONS

The Panel finds that in order that sufficient evidence be available to reach a decision respecting the well, the well must be completed and tested. The Panel recommends that the completion and testing be allowed to proceed subject to the following conditions:

- Procedures shall comply with the criteria set out in Interim Directive ID 90-1, Completion and Servicing of Sour Wells.
- Ranchmen's shall comply with all criteria as set out in the Sour Gas Flaring Permit for the well, RANCHMEN'S ET AL KNOPCIK 7-19-74-11, issued from the offices of the Board on 31 July 1990.
- An emergency response plan which encompasses the interveners' residences shall be prepared.
- The well site shall be manned on a 24-hour basis during completion and testing operations, unless the well is shut in.
- Ranchmen's shall inform the Board and the interveners as to Ranchmen's position with respect to the abandonment, suspension, or production of the well as soon as practical after completion of well testing.

DATED at Calgary, Alberta, on 23 October 1990.

ENERGY RESOURCES CONSERVATION BOARD

E. J. Morin
Board Member

ENERGY RESOURCES CONSERVATION BOARD
Calgary, Alberta

HUSKY OIL OPERATIONS LTD.
SUBSURFACE DISPOSAL OF PRODUCED WATER
FISHER AREA

Decision D 90-17
Application 891183

1 INTRODUCTION

1.1 Application

Husky Oil Operations Ltd.(Husky) applied, pursuant to section 26, subsection (c) of the Oil and Gas Conservation Act, to dispose of water produced from its Caribou Lake Experimental Scheme in the Fisher Area (Board Oil Sands Approval No. 5815) by injection into the Keg River Formation through the well, HUSKY AEC FISHER 8D-12-69-5 (8D-12 well) and, in the event the Keg River Formation cannot meet Husky's requirements, into the McMurray Formation through the 8D-12 well and the well, HUSKY AEC SWD FISHER 9-12-69-5 (9-12 well). Both wells are located west of the 4th meridian.

1.2 Hearing and Intervention

The application was heard on 24 October 1990 at a public hearing in Grand Centre, Alberta, before Board Members J. P. Prince, Ph.D. and B. F. Bietz, Ph.D., and Acting Board Member W. G. Remmer, P.Eng. Two interventions were filed with respect to this application.

Alberta Energy Company Ltd., a partner with Husky in its Caribou Lake Experimental Scheme, intervened in support of Husky's application.

The Cold Lake Community Advisory Committee intervened to oppose the application, particularly as it pertained to disposal of produced water into the McMurray Formation.

The following table lists the participants at the hearing.

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Husky Oil Operations Ltd. (Husky) S. M. Purcell J. A. Schnider	P. B. Carlson, P.Eng. H. R. Holt, P.Eng. R. G. Leishman, P.Geol. D. A. McCoy W. K. Smink, P.Eng. R. C. Wilson, P.Eng.
Cold Lake Community Advisory Committee (CAC) D. B. Appleby	D. B. Appleby S. F. Brule T. R. Ganske

THOSE WHO APPEARED AT THE HEARING (cont'd)

Principals and Representatives (Abbreviations Used in Report)	Witnesses
Alberta Energy Company Ltd. (AEC) A. F. Kiernan, P.Eng.	
Energy Resources Conservation Board staff D. A. Dolph, P.Geol. N. N. Nastasa, P.Geol. P. J. Oscienny, P.Eng. V. J. Vogt	

2 ISSUES

The Board considers the issues to be

- the need for subsurface disposal, and
- the suitability of the Keg River and McMurray Formations for disposal.

3 CONSIDERATION OF THE APPLICATION

3.1 Views of Husky

Husky applied to dispose of water produced from its experimental steam stimulation scheme in the Fisher Creek Sector of the Cold Lake Oil Sands Area (Husky's Caribou Lake project). The experimental pilot scheme involves the recovery of bitumen from the Clearwater Formation, as shown on Husky's stratigraphic column figure, attached. Husky indicated that it would need to dispose of approximately 400 to 600 cubic metres (m^3) of produced water per day over the 7-year life of the pilot scheme.

Husky discussed various options for the disposal of the produced water, including trucking, pipelining, recycling, and subsurface disposal.

Husky investigated trucking the produced water to an existing disposal well some 20 kilometres (km) from the pilot project but did not favour this option because of the human and environmental risk associated with 25 truckloads per day. Husky contended that, although truck spills would be small, they would be difficult to clean up in muskeg prevalent in the area. As an alternative, Husky investigated pipelining produced water to the same disposal well. This option was also not favoured because of the required length of the pipeline, the difficulty of detecting leaks, and the incremental environmental risk compared to disposal on site.

Husky stated that while it agreed with the CAC that disposal volumes should be minimized, the purpose of the experimental pilot scheme was to evaluate numerous options, including recycling and reuse of produced water for future incorporation into a commercial project. Husky indicated that for the pilot project, deepwell disposal on site is the best disposal method available.

Husky originally proposed that the McMurray Formation be the sole disposal zone for produced water from its Caribou Lake project. However, concerns raised by the CAC concerning disposal into the McMurray Formation caused Husky to evaluate potential disposal into the deeper Cambrian and Keg River Formations in the vicinity of the experimental pilot scheme.

Husky agreed with the CAC that preference should be given to using the deepest available zone provided the zone would accept sufficient volumes. Husky indicated that the deepest formation it considered was the Cambrian Formation, which it said is used as a disposal zone by Amoco Canada Petroleum Company Ltd. at a site approximately 20 km from the Caribou Lake project. However, based on geophysical and geological data, Husky concluded the Cambrian Formation at its site would not provide an adequate reservoir for the disposal of produced fluids.

Husky deepened the 8D-12 well to approximately 860 metres to evaluate the disposal potential of the Keg River Formation. Evaluation of the well logs and core data from the 8D-12 well showed significant porosity and permeability in the Keg River Formation in the area surrounding the wellbore. A short-term injectivity test found that the zone had characteristics suitable for subsurface disposal. Therefore, Husky amended its application to name the Keg River Formation as the primary disposal zone. The amended application also requested approval of the McMurray Formation as an alternative disposal option in case the Keg River Formation did not have the capacity to accept all the produced water from the pilot scheme. Husky noted that shutting down the operating cyclic steam process while an application was made for an alternative disposal zone would be detrimental to the efficiency of the project.

With respect to the McMurray Formation, Husky indicated that the zone, at an approximate true vertical depth of 575 metres, is made up of a large, mappable, thick sand known for its continuity and excellent reservoir quality, containing bitumen and non-potable water resources. Husky stated that the McMurray Formation is confined below by the tight Beaverhill Lake Formation and above by McMurray shales, lower Wabiskaw silts and mudstones, and the Wabiskaw shale. Husky indicated that the nearest known McMurray outcrop occurs some 193 km away at the Athabasca River and that a number of McMurray disposal wells are currently operating in the Cold Lake Area. Furthermore, the thick 150-metre Colorado shales add additional constraints to the potential migration upward into the freshwater sands near the surface. The cyclic steam operation proposed for the Clearwater Sand would also provide further protection since movement of fluids into this zone would be detectable as increased water production.

Husky evaluated and ruled out the Lower and Upper Grand Rapids and Upper Clearwater Sands as disposal options because future drilling into the Clearwater Sands may encounter these potential fluids disposed from the pilot project.

With respect to the potential for loss of produced waters into other formations, Husky was of the view that this was highly unlikely and furthermore would be detected rapidly by its proposed monitoring program. Anticipating that the only source of problem would be a wellbore failure, Husky took measures to confirm wellbore integrity, determining that cement covered the full length of both surface and production casing in the 8D-12 and 9-12 wells and in a third well, HUSKY AEC FISHER EX 7C-12-69-5, which will be completed as a production well in the pilot. As a further protective measure Husky used a high grade of casing and thermal cement for all wells penetrating the proposed disposal zones. Husky stated that it would operate the proposed disposal wells below the fracture pressure of the disposal formation, in order to prevent fracturing which could make subsequent communication among the formations more likely.

With respect to monitoring of the disposal wells and other production operations, Husky stated that it would routinely monitor the following:

- daily injection rates,
- changes in injectivity using a wellhead pressure gauge,
- annular pressures and fluid levels daily (to ensure isolation of injection fluids from inhibited annular fluids and to warn of steam in contact with disposal wellbores), and
- production from the experimental scheme to determine any change in characteristics that might indicate problems.

In addition, the injection pump would be equipped with a relief valve set below the fracture pressure of the formation, and a fall-off test would be conducted once per year to determine reservoir pressure. Husky concluded that all these measures would greatly reduce the risk of loss of disposal fluids to other formations.

3.2 Views of AEC

AEC Oil and Gas Company, A Division of AEC, submitted an intervention in support of Husky's proposed Caribou Lake project. AEC stated that it is a 40 per cent partner in the subject project. AEC reviewed the Husky water disposal application and supported the engineering design of the disposal well completion, proposed operations, and use of the McMurray Formation for pilot operations. AEC maintained that its experience with McMurray disposal operations 40 km north of the proposed Husky location has shown the McMurray Formation to be a suitable and reliable zone for disposal.

3.3 Views of CAC

The CAC outlined its concerns regarding the subsurface disposal of produced water in the Fisher Area. The CAC acknowledged Husky's need to dispose of the produced water. However, it believed that measures must be taken to protect the groundwater resources in the headwaters of the Cold Lake and Beaver River basins, and that Husky should place more emphasis on groundwater protection in the area. The CAC was particularly concerned because it believed that should Husky's disposal wells fail, the disposal water could migrate to surface and contaminate groundwater. The CAC was especially concerned with disposal into the McMurray Formation because of its shallow depth. In support of its concern, the CAC referenced two well failures in the Board-designated Cold Lake Oil Sands Area.

The CAC stated that emphasis should be placed on reducing the disposal volumes from the Caribou Lake project through recycling and reuse. Where disposal is necessary, the CAC indicated it should be to the deepest possible formation. In this regard, the CAC referenced a 1979 Board decision, ERCB REPORT 79-E, requiring disposal into the Cambrian zone rather than the McMurray Formation. However, the CAC acknowledged that the Cambrian was not present at Husky's Caribou Lake project, and therefore believed that the produced water should be transported either by truck or pipeline to a disposal well where injection into the Cambrian Formation was possible. The CAC stated a less preferable option would be to dispose into the deepest possible formation in the area, the Keg River Formation.

3.4 Views of the Board

With regard to the first issue of the need for subsurface disposal, the Board notes that this was not directly questioned by the CAC, although it did ask about the potential for recycling. The Board believes that Oil Sands Approval No. 5815 for Husky's Caribou Lake project establishes a need to treat and/or dispose of produced water from that project. Since the project is experimental and the quantity of produced water would be relatively small, the Board does not believe a requirement for recycling would be appropriate at this time. However, the Board would expect Husky to structure the project in a manner that will allow evaluation of the potential for recycling should the project expand to commercial size. A regular report on this evaluation will be a condition of the approval. The Board also expects Husky to minimize the disposal volumes to the extent possible and, regardless of the volumes, the Board will require measures to protect bitumen resources, groundwater, and the environment.

The disposal volumes applied for are in the order of 220 x 10^3 m^3 of produced water per year for a maximum of 7 years. The Board notes that the application is for the maximum possible volumes; therefore, the Board recognizes that the disposal of lesser volumes may be realized.

The Board has carefully evaluated the various options for disposal proposed by both Husky and CAC and notes that, regardless of the option chosen, subsurface disposal of the produced water will be required. The Board believes that the inherent risks of transporting the produced water off site, either by truck or pipeline, are greater than that of disposing of the produced water into an appropriate formation accessible from the site.

The Board acknowledges the 1979 Board decision, ERCB REPORT 79-E, that stated that the deepest acceptable formation should be used. However, it concurs with Husky that the Cambrian Formation is inadequate at this location; therefore, a shallower formation must be used.

In evaluating the suitability of on-site disposal formations, the Board considers the relative risk of the disposal fluid migrating and ultimately contaminating or affecting recovery from a formation containing either crude bitumen or usable groundwater. The Board is confident that the impermeable zones lying above both the Keg River and McMurray Formations will provide a sufficient barrier to contain disposed fluids. The Board notes that the integrity of the formation will be further ensured by maintaining disposal pressures below levels that could fracture the formation.

The Board agrees that, in the unlikely event of a contamination problem occurring, it would likely result from a wellbore failure, with that particular risk being similar regardless of whether the disposal is into either the Keg River or the McMurray Formation. The Board carefully evaluated the completion data for the three wells penetrating the proposed formations and believes that the measures that have been taken to prevent migration of disposed fluids are adequate. The Board is also confident that the volumes required by Husky for disposal into the McMurray Formation will not impede any potential bitumen recovery from that zone.

The Board shares the concerns of the CAC regarding the importance of the Caribou Lake headwaters area and the fact that usable groundwater must be protected. Of the two well failures referenced by the CAC, the Board notes that the one was a result of a poor completion, and the second, of inadequate cementing. In the case of Husky's wells, the adequacy of the completions has been confirmed. However, regardless of the adequacy of the completion techniques, the Board believes that monitoring measures must be in place to ensure that the integrity of the wellbore is maintained. The Board has examined the monitoring measures proposed by Husky, and considers them appropriate to ensure detection of problems before the disposed fluids could affect usable groundwater. The approval will be conditional upon detailed monitoring to ensure early detection of any problems, however unlikely.

As previously indicated, the Board agrees with the principle of disposal into the deepest possible formation, in this case the Keg River Formation. However, the Board recognizes and appreciates Husky's concern regarding the adequacy of the Keg River Formation to accept the disposal fluids over the life of the project. Therefore, the Board is prepared to allow immediate but temporary use of the McMurray Formation as a disposal zone if the Keg River Formation appears inadequate. Continued use of the McMurray Formation as a disposal zone over the life of the cyclic steam project, though, would only be authorized if a review by the Board of the data indicates that it is not feasible to dispose into the Keg River. Thus, the Board will require from Husky, within 60 days of the commencement of disposal operations into the McMurray Formation, a report outlining the reasons why the Keg River Formation is no longer suitable for disposal purposes.

4 DECISION

Subject to the approval of the Minister of the Environment, the Board is prepared to issue an approval to Husky for disposal into the Keg River Formation through the well, HUSKY AEC FISHER 8D-12-69-5, and in the event the Keg River cannot meet Husky's disposal requirements, the Board is prepared to authorize disposal into the McMurray Formation through the 8D-12 well and the well, HUSKY AEC SWD FISHER 9-12-69-5.

As a stipulation of the approval the Board plans to require Husky to submit an annual report outlining the results of monitoring and other matters as follows:

- an evaluation of the recycling potential of the produced water during the experimental pilot scheme operation,
- information on the effects of or changes to the groundwater levels in the subject area, and/or change in fluid composition,
- the pressure or fluid level of the tubing-casing annulus of each well, which is to be observed daily and recorded weekly,
- any liquid volumes added to the annulus of any of the disposal wells,
- the tubing injection pressure of the wells at surface, which is to be observed daily and recorded weekly,
- a summary of monthly injection volumes and yearly packer integrity tests,
- an interpretation of the results of the static bottom-hole pressure surveys and injection pressure monitoring with respect to injectivity and reservoir storage capacity, and
- a discussion of the overall performance of the disposal schemes, including any problems or modifications with respect to wellbore integrity and packer isolation tests.

The Board will also condition the subsurface disposal approval to expire at the termination of Husky's experimental pilot project relevant to the subject application. Should Husky wish continued subsurface disposal at the end of the pilot project, it will be required to reapply.

Finally, the Board expects Husky to abide by all the terms of its approval and, as a prudent operator, to immediately contact the Board should any problems develop with the disposal schemes. Husky will also be required at that time to identify its remedial measures to alleviate those problems.

DATED at Calgary, Alberta on 1 February 1991.

ENERGY RESOURCES CONSERVATION BOARD

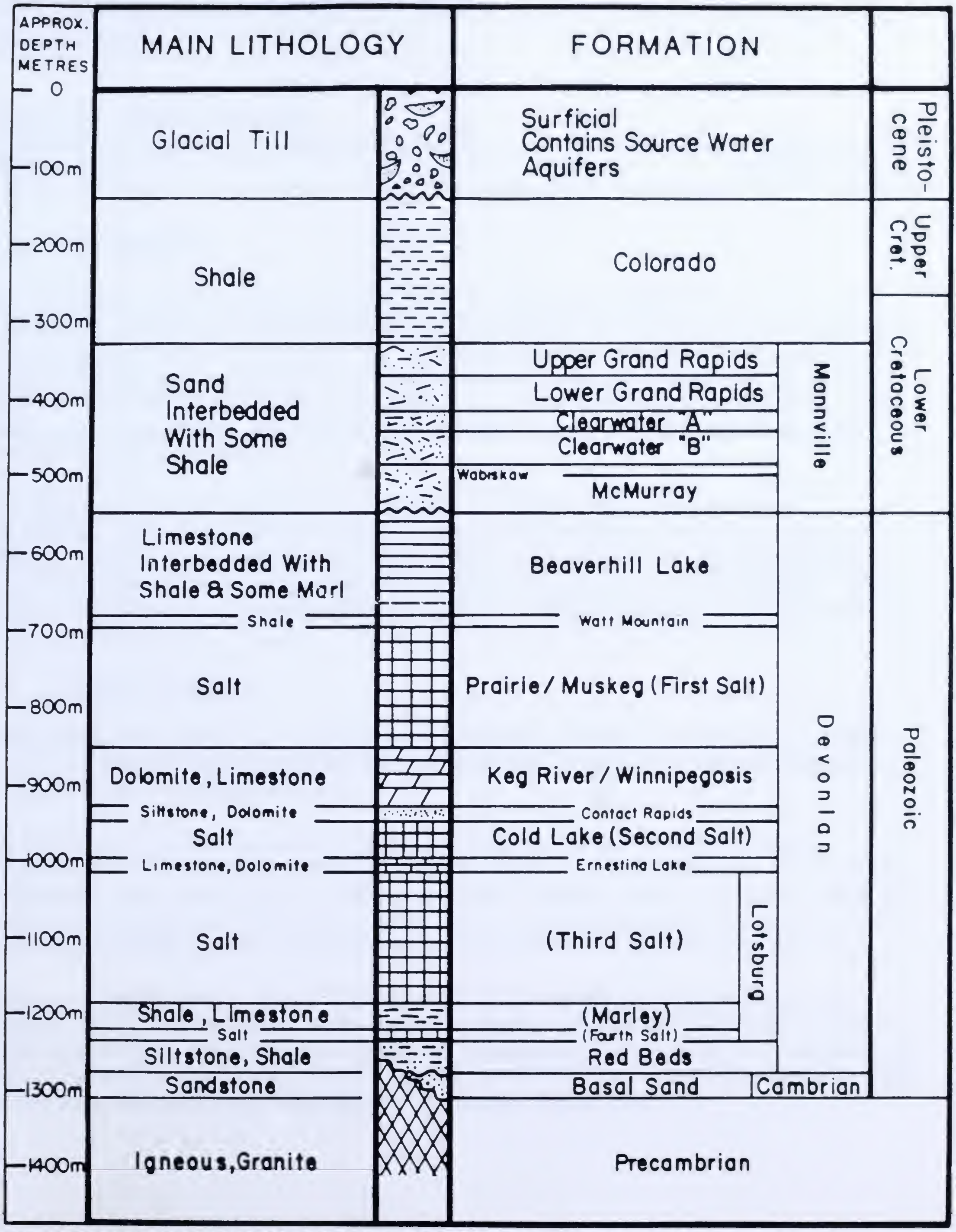
J. P. Prince

J. P. Prince, Ph.D.
Vice Chairman

B. F. Bietz, ~~Ph.D.~~

B. F. Bietz, ~~Ph.D.~~
Board Member

W. G. Remmer, P.Eng.
Acting Board Member



CARIBOU LAKE CYCLIC STEAM PILOT. Stratigraphic column.
Taken from Husky Oil Operations Ltd. application.

ENERGY RESOURCES CONSERVATION BOARD

Calgary, Alberta

HUSKY OIL OPERATIONS LTD.
SUBSURFACE DISPOSAL OF PRODUCED WATER
FISHER AREA

Addendum to Decision D 90-17
Application 891183

1 BACKGROUND

On 1 February 1991, the Board issued Decision D 90-17 respecting an application by Husky Oil Operations Ltd. (Husky), made pursuant to section 26, subsection (c) of the Oil and Gas Conservation Act, to dispose of water produced from its Caribou Lake Experimental Scheme in the Fisher Area (Board Oil Sands Approval No. 5815) by injection into the Keg River Formation through the well, HUSKY AEC FISHER 8D-12-69-5 (8D-12 well), and, in the event the Keg River Formation cannot meet Husky's requirements, into the McMurray Formation through the 8D-12 well and the well, HUSKY AEC SWD FISHER 9-12-69-5.

Since the issuance of that decision, Husky informed the Board through a submission dated 13 February 1991, that it believes the decision misquoted its views under Section 3.1, "Views of Husky". Husky is concerned that if its position is not clearly understood, it may compromise its credibility regarding any future application for McMurray disposal in the Cold Lake Region. The purpose of this addendum is to clarify Husky's position as it relates to subsurface disposal for the subject application.

2 HUSKY'S POSITION

Husky indicated that while it substantially agrees with the Board's decision as laid out in Decision D 90-17, it disagrees with the stated interpretation of its views regarding the subsurface disposal of produced water into the McMurray zone.

Husky interprets the decision report to say that Husky agrees with the Community Advisory Committee (CAC) that preference should be given to using the deepest available zone for the disposal of produced water, provided the zone will accept sufficient volumes. Husky believes that there is no publication or record of it taking such a position; rather, it believes its position on record has always been that the McMurray zone is the most suitable zone in the area for its disposal requirements.

Husky's original proposal to dispose of project water into the McMurray zone represents, in its opinion, the best disposal option. Husky states that it agreed to deepen the 8D-12 well to the Keg River Formation and evaluate the zone for disposal purposes only to accommodate the concerns of the CAC. Furthermore, Husky believes that it agreed to use the Keg River zone for disposal only so long as that zone demonstrates continued capability as a suitable disposal zone.

The Board acknowledges that the position set out above represents Husky's views as they were presented at the hearing.

DATED at Calgary, Alberta, on 2 May 1991.

ENERGY RESOURCES CONSERVATION BOARD

J. P. Prince

J. P. Prince, Ph.D.
Vice Chairman

B. F. Bietz, Ph.D.
Board Member

W. G. Remmer, P. Eng.
Acting Board Member

ENERGY RESOURCES CONSERVATION BOARD

Calgary Alberta

THE CITY OF MEDICINE HAT
POWER PLANT EXPANSION

Decision D 90-18
Application 901544

By Application 891967, registered on 28 December 1989, The City of Medicine Hat (the City) applied for approval to expand its power plant in two phases. Phase I of the expansion would consist of installing a 17-megawatt (MW) gas turbine unit in 1990 followed by a second 17-MW gas turbine unit and associated waste heat recovery boilers for combined cycle operation by 1992. In Phase II, a 30-MW steam turbine unit would be installed by 1996. The proposed expansion would provide the City with needed reserve capacity starting in the summer of 1991 and would satisfy all of the City's projected needs to the year 2003.

The application was considered by the Energy Resources Conservation Board (the Board or ERCB) at a public hearing in Medicine Hat on 17 and 18 April 1990. The Board issued Decision D 90-5 on 7 August 1990. The Board found the proposed expansion to be technically and environmentally acceptable. It agreed that the City would require reserve capacity until about 1993 and additional firm capacity thereafter. However, the Board also found that there would be an economic benefit to all Alberta electric consumers, and the public interest would be better served, if the proposed expansion were deferred for 2 or 3 years and the City supplied with reserve capacity from the surplus capacity that exists on the Alberta interconnected system (AIS). The surplus capacity on the AIS is likely to exist until about 1993. Accordingly, the Board denied the application without prejudice.

Subsequent to the release of Decision D 90-5, the City entered into an agreement with TransAlta Utilities Corporation (TransAlta) for the purchase of firm energy during the peak summer months from 1991 to 1993 inclusive. By Application 901544, registered on 23 October 1990, the City again applied to the ERCB for approval to expand its power plant. The current application proposes to install the gas turbine units and heat recovery boilers for operation by the fall of 1993 and the steam turbine unit by 1996. Additionally, because the City has already purchased the first of the two gas turbine units, it requests permission to immediately install the unit to allow it to conduct acceptance tests.

Having considered Application 901544, and having regard for the following:

- the applied-for facilities have already been found to be technically and environmentally acceptable,

- the views of affected parties were considered at and following the recently completed hearing,

- the City has complied with the Board's direction and has entered into an agreement with TransAlta that takes advantage of the current surplus capacity on the AIS,

- the City has deferred the first phase of its proposed expansion until the fall of 1993, and

- there have not been any substantially changed circumstances since the Board issued Decision D 90-5,

the Board has decided to grant the application. Accordingly, it will proceed to request authorization of the Lieutenant Governor in Council to issue an approval to the City and will refer the application to the Minister of the Environment for his approval of the application as it affects matters of the environment.

DATED at Calgary, Alberta, on 15 November 1990.

ENERGY RESOURCES CONSERVATION BOARD

N. A. Strom, P.Eng.
Vice Chairman